JULY 2007

TECHNOLOGIES

for producing transportation fuels, chemicals, synthetic natural gas and electricity from the gasification of Kentucky coal

UNIVERSITY OF KENTUCKY
CENTER FOR APPLIED ENERGY RESEARCH
"An Equal Opportunity University"

A Report in Response to HB 299 Sections 3 (1), (2) and (6).

Technologies for Producing Transportation Fuels, Chemicals, Synthetic Natural Gas and Electricity from the Gasification of Kentucky Coal

A Report in Response to HB 299, Sections 3 (1), (2) and (6)

July 2007

University of Kentucky
Center for Applied Energy Research

(Page left blank intentionally.)

Technologies for Producing Transportation Fuels, Chemicals, Synthetic Natural Gas and Electricity from the Gasification of Kentucky Coal

A Report in Response to House Bill 299, Sections 3 (1), (2) and (6)

July 2007

D. Gray, [1]***; D. Challman***[2]***; A. Geertsema***[3]***; D. Drake***[3]***; and R. Andrews***[2]

(Portions contributed by faculty and staff of the Coal Fuel Alliance: University of Kentucky, Purdue and Southern Illinois University)

Edited by D. Challman[2]***.***

[1] ***Mitretek Systems;*** [2] ***University of Kentucky Center for Applied Energy Research;*** [3] ***Consultant***

(Page left blank intentionally.)

Table of Contents

List of Tables and Figures

(Page left blank intentionally.)

Executive Summary

I. Purpose and Background: HB299

There are significant opportunities for the expanded use of coal as a means to replace imported petroleum and petroleum products for transportation fuels and chemicals by using coal-to-liquids (CTL) technology and from the production of synthetic natural gas (SNG) from coal. The use of coal for these purposes can provide additional independence from oil imports, safeguard the nation's security, allow for the development of new industries, and provide new incentives for coal production. The Department of Defense has a keen interest in securing alternatives to petroleum for reliable supplies of battlefield and jet fuels, and this effort is well aligned with that objective. Moreover, Fischer-Tropsch coal-derived fuels are environmentally superior to petroleum-derived fuels. The products include ultra-clean diesel and jet fuel of interest to the aviation, heavy equipment and trucking industries. Kentucky's coals are excellent feed stocks for these purposes.

Recognizing these facts, the 2006 Regular Session of the General Assembly of the Commonwealth of Kentucky enacted HB 299, the Kentucky Energy Security National Leadership Act. The purpose of the Act is to bring about the development and implementation of a strategy for the production of transportation fuels and synthetic natural gas from both fossil energy resources and biomass resources. The strategy is intended "to ensure that Kentucky will lead the states in securing the energy independence of the United States and will consequently benefit from economic growth and stabilization of the Commonwealth's coal industry and agriculture" that will result from the development of this new industry in Kentucky.

II. About this Report

House Bill 299 states "(T)o ensure that Kentucky will lead the states in securing the energy independence of the United States and will consequently benefit from economic growth and stabilization of the Commonwealth's coal industry and agriculture, the Kentucky Office of Energy Policy shall develop and implement a strategy for production of transportation fuels and synthetic natural gas from fossil energy resources and biomass resources." The Office of Energy Policy initiated a Memorandum of Agreement with the University of Kentucky Center for Applied Energy Research (CAER) under which the CAER would provide a description and technical and economic assessment of technologies for producing transportation fuels, synthetic natural gas, chemicals, and electricity through gasification of coal, specifically Kentucky coals. The assessment was to address the following sections of the Act:

Section 3 (1). *Technologies available or in use for producing transportation fuels and synthetic natural gas from fossil energy resources relative to advantages of these in terms of process efficiencies, environmental performance, and marketable products including chemicals, industrial feed stocks, and electricity;*

Section 3 (2). *Research, demonstration, and commercial-scale construction and operation of one or more technologies, and follow-up expansion; and*

Section 3 (6). *Industry participation, both by single firms and by consortia, in research, development, construction, and operation of alternate transportation fuels or synthetic natural gas plants.*

This report is in fulfillment of that Memorandum of Agreement.

Available technologies for CTL and SNG were considered and evaluated based on plant economics, the suitability of Kentucky coals, and environmental considerations. The assessment also considered plant site requirements for a typical or generic CTL and SNG plant, including acreage required for construction, operations and expansions, and construction and operational workforce requirements.

A detailed economic assessment was made for nine generic process cases using sophisticated computer simulation models of CTL and SNG facilities. The models simulated the gasification of coal to clean synthesis gas and the subsequent utilization of this synthesis gas for generation of electric power, for CTL or for the production of SNG. The models provide complete material and energy balances and are flexible with respect to coal feedstock, technology, plant size, and configuration. They also estimate capital and operating costs and calculate the required selling price (RSP) of products based upon specified financial assumptions.

Cases for CTL and SNG were done on a typical Eastern Kentucky and Western Kentucky coal. Six CTL cases were evaluated, which used a reference production capacity of 10,000 bbl/day of ultra-clean diesel. The same size plant in terms of coal use was used for an additional three SNG cases, which used a reference production capacity of 74 MMscfd of pipeline quality substitute natural gas.

The balance of this report provides an indication of the outstanding needs for research, development and demonstration of CTL and SNG plants. Hurdles associated with deploying these pioneering energy technologies are identified. The value and benefit of improvements, know-how, show-how and experience is discussed as a means of reducing risk and improving investor confidence. Specific unmet technology needs and the requirements for labor force development are also identified.

The report ends with a discussion of the role of industry and government in CTL and SNG. It describes important teaming considerations when choosing equipment vendors; engineering, procurement and construction contractors (EPCs); and operating companies – the sort of "owner-operators", equity interest and "wrap arounds" that exist now or are needed to provide performance guarantees and other assurances to reduce financial, technical and operating risk. Candidate technologies are described by equipment vendor, including the current maturation of available technologies. A listing of the corporations, joint ventures and other consortia that exist today to finance, construct and operate CTL or SNG plants is provided. The role of government at the federal, state and local level to stimulate the deployment and commercialization is also discussed.

III. Findings and Conclusions

Rationale for CTL and SNG from Coal

- There are significant opportunities for the expanded, diversified use of coal as a means to replace petroleum and petroleum products in higher value-added markets for transportation fuels, chemicals, and substitute natural gas. The use of coal for the latter purposes can provide additional independence from oil imports, safeguard the nation's security, allow for the development of new industries, and provide new incentives for coal production. The production of substitute natural gas can help to stabilize the price of gas and keep America from becoming dependent on imported natural gas in the same way that it is dependent on imported petroleum and petroleum products. Kentucky's coals are suitable feed stocks for the production of transportation fuels and substitute natural gas.

- World petroleum prices establish the hurdle rate at which alternative fuel technologies will become economical, in the absence of factors outside the market to speed their deployment. Since current CTL processes can produce a slate of premium fuels in the range of $50/bbl on a crude oil equivalent basis, the question is: Have we not yet reached the "trigger price" for coal liquids considering that petroleum prices currently hover in the range of $60/bbl. According to the USDOE's Energy Information Administration, the long-term outlook for petroleum prices indicate a continuing rise to a level of nearly $100/bbl by 2030. Likewise, substitute natural gas from coal can be produced in the range of $7.50 to $8.00/MMBTU, while the current Henry Hub price is around $8.00/MMBtu. While not as volatile as petroleum, natural gas prices are expected to remain in the range of $7.00 to $8.00/MMBtu through 2030. However, gas prices vary considerably with winter temperatures and electric power demand. In the past several winters, the price of natural gas has spiked to around $14.00 per thousand cubic feet. The conventional wisdom is that prices will remain high, and certainly will not return to the low prices enjoyed during the past decade.

- As coal-derived liquids capture a greater and greater share of the domestic market, it will lower oil import requirements and improve the US balance of trade. Income realized by producers of synthetic fuels (as well as their suppliers and employees) stays within Kentucky and the United States. These direct benefits multiply throughout the economy. Lower prices for a major factor of production translate to lower inflation and higher GDP. Homeland security is enhanced by less dependence on foreign petroleum, particularly from unstable regions of the world.

Technical and Economic Evaluation of CTL/SNG using Kentucky Coals

- The production of liquid transportation fuels and chemicals from coal (CTL) can be accomplished via two basic approaches - direct or indirect liquefaction. At the present time, indirect liquefaction by Fischer-Tropsch (FT) synthesis appears to be the preferred route because of its greater commercial experience, lower capital cost, flexibility in coal feed, plant efficiency, environmental performance, and the higher product quality of end-use fuels and chemicals.

- A detailed techno-economic feasibility study conducted by Mitretek for this study report for a generic 10,000 barrel per day (BPD) CTL plant has shown that ultra-clean diesel can be produced from Eastern and Western Kentucky coals using existing FT indirect liquefaction technologies in the range of $49.96 to $53.20 per barrel on a crude oil equivalent basis depending on coal type and plant configuration. [For larger scale CTL plants, economies of scale bring down costs to $45.50, $44.00 and $43.00 per barrel for 30,000, 60,000 and 100,000 BPD plants, respectively.]

- Mitretek's feasibility study of an SNG plant equivalent in size to a 10,000 BPD CTL plant - 74 million standard cubic feed per day (MMscfd) - has shown that pipeline quality substitute natural gas can be produced from Eastern and Western Kentucky coals using existing methanation technologies for between about $9.10 and $9.47 per million Btu's depending on coal type and plant configuration. [For larger scale SNG plants, economies of scale bring down gas costs to $7.50 to $8.00 MBtu.]

- The coal requirement for the relatively small capacity plants (10,000 BPD for CTL and 74 MMscfd for SNG) is estimated to be approximately 5,000 TPD of Kentucky coal. Applying a ratio of 2 bbl per 1 ton of coal to larger commercial-scale plants in the range of 30,000, 60,000 and 100,000 BPD results in coal requirements of about 15,000, 30,000, and 50,000 TPD, respectively. Assuming an average annual productivity of about 7,500 tons per man, a 10,000 BPD plant would result in employment of about 240 miners. Meeting the coal requirements of larger 30,000, 60,000 and 100,000 BPD plants would result in employment of about 730, 1460 and 2425 miners, respectively.

- The plant layout for either the 10,000 BPD CTL or 74 MMscfd SNG plant is estimated to require an approximate plot size of 2,556 x 2,500 feet or 150 acres. This includes key process units such as the gasification island, gas treatment, FT synthesis or methanation, and the power block as well as coal storage, transfer, and grinding. All offsites and utilities, exclusive coal conveying to the plant, roads and water wells and piping are also accounted for. The total footprint of the facility including coal conveying, rail spur for product shipment, roads, water wells, and pipelines to the plant is expected to be about 200 acres. The footprint for larger commercial-scale plants in the range of 30,000, 60,000 and 100,000 BPD is expected to require acreage of about 750, 1500, and 3000 acres, respectively. It should be noted that actual plant area requirements are site specific and dependent on capacity (particularly the number of gasification trains and built-in redundancy) and common area facilities for feedstock handling, product storage and shipping. Estimates given here could vary by as much as +/- 30 percent.

- Annualized capital costs and operating costs (including coal cost) contribute approximately equally to the required selling price (RSP) of either the finished liquid fuels or the SNG derived from Kentucky coal. The RSP is the selling price that would be required for finished products to satisfy the economic assumptions made in Mitretek's study, including a 15% return.

- For the CTL cases, Mitretek evaluated reactor performance which would lead to a greater make of diesel versus less valuable naptha; the naptha fraction was valued at about 71.4% of the diesel fraction since the naptha requires further upgrading to finished fuels. Reducing the naphtha to diesel ratio with a FT reactor performance modeled after known proprietary technologies reduces the RSP of the finished liquid products by about 3 percent.

- Mitretek also evaluated the efficiency penalty associated with adding the capability for carbon capture. When carbon capture is required for either the CTL or SNG cases, there is a small efficiency penalty of 2 percent for either CTL and SNG plants and a cost of product penalty of 3 percent for CTL and 4 percent for SNG. The efficiency penalty is small because even in the cases where carbon capture is not required, the carbon dioxide still has to be removed. The only difference is that the carbon dioxide has to be compressed to 2000 psi when capturing is necessary. This additional cost does not include the actual cost of sequestering this compressed carbon dioxide. Ideally this carbon dioxide could be used for enhanced oil recovery if there are suitable opportunities within a feasible distance from the plant.

- The water use requirements of Kentucky CTL or SNG plants are at or below typical utility averages. If water availability is an issue the plants could be redesigned for minimal water use by maximizing the use of air cooling. [Employing air cooling could reduce water usage significantly, which would otherwise be lost as cooling tower drift, evaporation and blowdown].

- Plant staffing for either of these relatively small plants (10,000 BPD for CTL and 74 MMscfd for SNG) is estimated to total about 190. This includes about 25 professionals and 115 operators, with the remainder being administrative, security, and maintenance labor. It is estimated that 650 to 1,100 construction workers will be needed on site for plant construction. Plant staffing for larger commercial-scale plants in the range of 30,000, 60,000 and 100,000 BPD is estimated to require up to 400, 630, and 880 professionals and skilled operators, respectively. Needed construction labor also increases to as many as 2,300, 3,650 and 5,100 construction workers, respectively for the larger capacity plants. These estimates may also vary by as much as +/- 30 percent.

- It should be cautioned that Mitretek's study is not a detailed engineering and economic analysis. It is a feasibility analysis using certain specified coal inputs to generic non site specific conceptual CTL and SNG plants. The technical performance of the plants is modeled in sufficient detail to have a high level of confidence in the overall product output, coal input, power and utilities consumption and hence overall efficiency. Because this analysis is at the feasibility level and non site specific, the accuracy of the construction cost estimates is expected to be about +/- 30 percent. However, although there is some uncertainty in the absolute costs, the cost differences between the cases are considered to be meaningful.

Needs for Research, Development and Demonstration

- CTL and SNG technologies offer the prospect of supplanting petroleum and natural gas – of producing clean fuels, chemicals and gases from an abundant domestic resource, but their commercial deployment is constrained by certain economic and technical barriers. The deployment of pioneering energy technologies bring with them certain financial and technical risk not normally associated with proven technologies. These include a greater capital risk associated with financing and constructing large projects, early siting risks and construction delays, product risk, and operating risk associated with the early operational performance of the plant.

- Absent performance guarantees or the taking of an equity position by the technology vendor and/or engineering, procurement and construction (EPC) company (so-called "wraps"), investors expect to be compensated for taking these added risks. Thus, the project hurdle rate for pioneering technologies is inevitably higher than that required for proven or mature technologies – especially for these exceptionally large and capital intensive projects.

- Risk can be reduced and deployment stimulated by a variety of means, including price supports, product take-off agreements, tax breaks, and financing incentives for early adopters. It can also be reduced by making "learning investments" for research, development and demonstration (RD+D) to reduce the technical hurdles of new energy technologies. It is an accepted premise that with successive deployments of a pioneering technology there comes with it learning and improved operational experience. There are a number of technical issues which, if addressed in creative ways, can alleviate some of the risks associated with the adoption of CTL technology.

- Efforts need to be made to build up human capital – the future generation of skilled energy technologists, engineers and operating personnel – that will be needed to sustain a CTL and SNG industry. A new generation of technologists needs to be nurtured. One of the best ways of creating this skills base is to stimulate and fund RD+D at appropriate institutions which have the facilities to teach and train students in the practical applications of science and engineering.

Role of Industry and Government in CTL and SNG

- Development of a commercial scale CTL or SNG plant will require a number of individual process steps which need to operate in harmony to ensure profitability. It is therefore critical that adequate consideration be given to the selection of technologies, vendors and other teaming partners.

- The chosen suppliers of technology should provide the needed warranties that their plants will perform as agreed, but warranties should also be obtained for the overall configuration. Such overall "wrap-around" warranties are hard to obtain since few plants have yet been erected in the USA. The best alternative is to select a reputable engineering, procurement and construction company (EPC) with experience and in-depth understanding of the technologies to be incorporated in the plants. These considerations extend to, besides the main gasification, SNG and FT sections, other parts of the plant, including gas cleaning, solid and effluent treatment/disposal, permitting, and logistics regarding feed and products transportation.

- It is an appropriate role of the federal government to provide a stimulus at the national level for the deployment of CTL and SNG through the provision of incentives, such as price supports, product take-off agreements, tax breaks, and financing incentives for early adopters. Similarly, it is also appropriate for the state and local authorities to work closely with industries and project developers to smooth the path toward commercialization. Along with the incentives mentioned above, support could include expeditious attention to permitting, provision of needed infrastructure which and working with local communities and interest groups to ensure that potential concerns are identified early and that involved parties are fully informed of the considerations for siting and operating such facilities.

- A strong team should drive the initiatives to attract entrepreneurs and investors. Part of this action could be to bring the appropriate partners together, because as of now there are not many significant teams with the wherewithal to deal with large multi-billion projects, especially teams involving all the parties (equipment vendors, engineering, procurement and construction contractors and plant owners/operators).

(Page left blank intentionally.)

Chapter 1: Rationale for CTL and SNG from Coal

This section addresses:

1. Political and market forces (homeland security, economic development, quality of life, environmental quality).
2. Substitution forces (world petroleum economics, oil price, and coal as a substitute).
3. Forecasts for development of CTL and SNG (plants, capacity, finished products market, imports, trade balance).

I. Introduction

In this report, the macro level rationale for CTL and SNG from geo-political and strategic perspectives is taken as known - and there have been good recent studies clearly making the case for action. Prominent in this regard is the study titled *The American Energy Security Study*, initiated by the Southern States Energy Board. The Governor's Office of Energy Policy was a leading sponsor. It is available at http://www.americanenergysecurity.org/studyrelease.html. Another significant study is the National Coal Council study titled *Coal: America's Energy Future.* This is available at http://www.nationalcoalcouncil.org/informat.htm. Below are some points in brief about the need and rationale of CTL and SNG from coal.

II. Homeland Security and Economic Development

Coal is the most abundant fossil energy resource in the US and in the world. Recoverable reserves in the US are estimated by EIA to be about 270 billion tons - nearly a 300 year supply at current rates of usage. Conversely, the US supplies only 40 percent of its oil needs from domestic sources since oil production is declining in the Lower 48 States as old wells are played out and require expensive enhanced recovery. The opening of new reserves offshore and in wilderness areas will come on stream only slowly, if at all. America does not have an energy shortage so much as a shortage of liquid transportation fuels. As a consequence, America will become increasingly dependent on imported oil, now at 60% of requirements, and taken largely from unstable regions of the world. In the balance is the nation's homeland security and global economic competitiveness.

There are very significant opportunities for the expanded, diversified use of coal as a means to supplant petroleum - in higher value-added markets for transportations fuels, chemicals and advanced materials. The use of coal for the latter purposes can provide additional independence from oil imports, safeguard the nation's security, allow for the development of new industries, and provide new incentives for coal mining. Current CTL processes can produce a slate of premium fuels in the range of $49.96 – 53.20/bbl on a crude oil equivalent basis for a 10,000 BPD plant. Economies of scale associated with larger 30,000, 60,000 and 100,000 BPD plants reduce costs to $45.50, $44.00 and $43.00 per barrel, respectively. The Department of Defense has a keen interest in securing alternatives to petroleum for reliable supplies of battlefield and jet fuels. Moreover, the composition of coal liquids differs from that of petroleum, such that there are certain applications where they are environmentally superior, for the production of ultra-clean diesel and jet fuel of interest to the aviation, heavy equipment and trucking industries.

The coal reserves in Kentucky represent enormous untapped energy potential. These reserves are suitable as feed stocks for the production of transportation fuels and synthetic natural gas (SNG). The development of such an industry will help to recapture a portion of Kentucky's lost share of coal production, stem the loss of thousands of jobs, and contribute to revitalizing communities in the Commonwealth.

III. Substitution Forces/ The "Trigger Price" for CTL and SNG

The cyclical interest in CTL and SNG can be attributed to the peaks and valleys of the world oil market. Petroleum underpins the price structure of all fossil fuels. Left to supply and demand, price signals producers to find and extract more resources. It signals consumers to seek the least-cost substitutes and to moderate consumption. It establishes the hurdle rate or "trigger price" at which alternative fuel and gas technologies will become economical, in the absence of factors outside the market to speed deployment. The latter includes such things as price supports, product "take" agreements, tax breaks, and financing incentives for early adopters. It also includes "learning investments" in research, development and demonstration (RD+D).

This is to say that without incentives to speed deployment coal-derived fuels and substitute natural gas will be economical when the cost of producing these alternatives is less than the market price of petroleum and natural gas. Since current CTL processes can produce a slate of premium fuels in the range of $50/bbl on a crude oil equivalent basis, the question is: Have we not yet reached the "trigger price" for coal liquids considering that petroleum prices currently hover in the range of $60/bbl. Likewise, substitute natural gas from coal can be produced in the range of $7.50 to $8.00/MMBTU, while the current Henry Hub price is around $8.00/MMBtu.

Aside from where oil and natural gas prices are today, a better question is: Will they remain high over the long-term? According to the USDOE's Energy Information Administration, the long-term outlook for petroleum prices indicates a continuing rise to a level of nearly $100/bbl by 2030 in their high price forecast. The average price of natural gas, while not as volatile as petroleum, is expected to remain in the range of $7.00 to $8.00/MMBtu through 2030. However, gas prices vary considerably with winter temperatures and electric power demand. This time last year the price of natural gas was about $14.00/MMBtu. The conventional wisdom is that prices will remain high, and certainly will not return to the low prices enjoyed during the past decade. However, as explained in the discussion of risk (p. 49), the high capital risk of financing and constructing pioneering energy technologies may require the cost of producing coal liquids to be well below the prevailing price of petroleum or may, conversely, require the rate of return to be relatively high to induce investment in plants that may cost several billions of dollars.

IV. Production, Balance of Trade and Other Benefits

In a simple example, consider the deployment of the first ten liquefaction plants in the US, each with a capacity of 100,000 bbl/day. Together these plants would supplant 1M bbl/day of hydrocarbon liquids produced domestically or imported, representing 5 percent of daily oil consumption in the US [8.3% of the 12 million barrels per day that are imported]. To meet the coal requirements of 1M bbl/day of coal liquids, coal production would also rise, and is estimated to require about 182 million short tons of coal (a 20 percent increase in current annual coal production).

As coal liquids capture a greater and greater share of the domestic market, it will also lower oil import requirements and improve the US balance of trade. In the above case, 1M bbl/day of coal liquids will reduce net imports by 8.3 percent over current levels, along with the attendant annual savings in import expenditures of $22Bn/year at the current oil price of $60/bbl. Cumulative savings over the life of these plants (conservatively estimated at 25 years) results in a half trillion dollars. Other tangible economic benefits will accrue from the introduction of CTL. Income realized by producers of synthetic fuels (as well as their suppliers and employees) stays within the United States. These direct benefits multiply throughout the economy. Lower prices for a major factor of production translate to lower inflation and higher GDP. The nation's trade balance is improved. Alternative fuels will help to ease price spikes and smooth out price variability. Finally, homeland security is enhanced by less dependence on foreign sources of natural gas and petroleum, particularly oil supplies from unstable regions of the world.

(Page left blank intentionally.)

Chapter 2: A Primer on CTL and SNG from Coal

This section addresses:

1. Alternative technologies for producing coal liquids and synthetic natural gas (process efficiencies, environmental performance, and product slate).
2. Why Fischer-Tropsch looks more promising (base of technology in gasification, already practiced at industrial scale, economies of scale, systems integration associated with polygen plants, stimulus associated with recovery of stranded gas, etc.).

I. Introduction

When coal came to prominence as a fuel during the Industrial Revolution, there developed in parallel its use for the production of materials and chemicals. By-product liquids and gases from coal carbonization processes became the basic raw materials for the organic chemical industry, and the production of metallurgical coke from coal was essential to the development of steel manufacture. Coal tar constituents were used for the industrial syntheses of dyes, perfumes, explosives, flavorings, and medicines, and later for producing strategic materials (binders, carbon fibers, adsorbents). Processes were also developed for the conversion of coal to gas and liquid fuels. Gases from coal carbonization and coke production were used for illumination as long ago as the late eighteenth century. By the 1930s direct and indirect liquefaction technologies became available for the large-scale conversion of coals to liquid transportation fuels and chemicals.

II. Coal Conversion Processes

Direct Coal Liquefaction via Hydrogenation

The production of hydrocarbon liquids from coal can be accomplished via two basic approaches - direct or indirect liquefaction. Direct liquefaction is accomplished by converting the organic matter in coal *directly* to a liquid by hydrogenation – a process of breaking up the solid matrix of coal, bringing it into solution (in a process solvent) and effecting further reductions in molecular size to produce distillate products. The process involves large amounts of hydrogen at elevated temperatures and pressures, and significant de-ashing and solids recycle. The slate of products includes synthetic gasoline and diesel as well as LPG, and heavy tar which can be used for value-added materials.

The process of direct hydrogenation of coal was first discovered by Bertholet in 1869 and was advanced by the work of Bergius, Farben and others in the mid-1900s. Bergius demonstrated the commercial viability by 1927, and Farben was responsible for the first commercial-scale production in Germany. Direct liquefaction plants were subsequently constructed and operated in England (1935 and 1958); Louisiana, Missouri (1949); Institute, West Virginia (1952); Baytown, Texas (1980s); Ft. Lewis, Washington (1980's); Catlettsburg, Kentucky (1980s); Wilsonville, Alabama (1990's); Victoria, Australia (1990's); and Japan (1990's). There are currently large direct liquefaction facilities being erected in China.

Indirect Coal Liquefaction via Fischer-Tropsch Synthesis

The *indirect* approach first converts the coal to a synthesis gas (primarily hydrogen and carbon monoxide) via coal gasification, and then making synthetic fuels from the syngas in a catalytic process, called the Fischer-Tropsch (FT) process – named after its inventors. Synthetic middle distillates produced via FT synthesis can be used as ultra-clean diesel or in blends with petroleum-derived diesel.

After Fischer and Tropsch invented the conversion of synthesis gas to liquid products, the German company Ruhrchemie commercialized the process and built the first Fischer-Tropsch (FT) plants in 1936 in Germany. Indirect coal liquefaction plants were subsequently constructed and operated in South Africa, including the Sasol I plant (1955) and two additional plants at Secunda (1980's). Numerous feasibilities studies are currently under way for construction of indirect coal liquefaction plants in various countries, including the USA, China, India and South Africa.

Other routes include gasoline via the route of first making methanol from the syngas, and then converting methanol to gasoline (the MTG process). This process is not in commercial production any more, although it was practiced for a brief period in New Zealand. Other oxygenated fuels such as dimethyl ether (DME) can also be produced. However, in China, DME has not yet grown to commercial significance as a fuel, mainly due to difficulties with the logistics of product distribution.

Coal to Synthetic Natural Gas via Methanation

The production of Synthetic Natural Gas (also referred to as substitute natural gas) is a way of converting coal into the equivalent of pipeline quality natural gas. The technology involved in SNG production is much less cumbersome than for CTL. The main reaction is to convert the syngas produced from coal gasification to methane in a methanation reactor and the product gas is then adjusted to meet natural gas pipeline specifications. The reaction is typically catalyzed by nickel catalysts and it is best performed at high temperatures (1,300 to 1,800 degrees F) where additional heat is liberated, which can be used in the gasification process. Commercial catalysts and technology are available.

SNG from coal is particularly attractive in situations where relatively cheap coal is available while there is a demand for natural gas (methane) which might be logistically constrained or when natural gas prices are high enough to sustain the economics. During the late 1970's there was concern about the "shrinking gas bubble". In response, the Great Plains Gasification project in North Dakota was developed and commissioned in the 1980's. The history of this facility is well documented. The DOE was an active participant with a loan guarantee at a cost of $1.8 billion. Due to commercial and contractual difficulties and falling natural gas prices, the facility went through difficult times. After a large part of the capital investment was written off, the facility is currently in a strong financial position due to favorable gas prices and its diversification into co-producing several chemicals such as phenolics and noble gases. Over the years production has been gradually increased to about 165 million scf/d SNG from about 17,000 t/day of lignite. The environmental performance of the facility has also improved, meeting all permit requirements. More recently even the carbon dioxide from the plant is profitably sequestered for enhanced oil recovery.

Poly-generation, Co-generation and Hydrogen Production

Coal liquids can in principle be produced as a co-product in advanced IGCC power plants which are also based on coal gasification to produce synthesis gas. The combination of CTL and IGCC is often referred to as poly-generation. The liquids could either be FT liquids or methanol and, at least conceptually, the liquids produced could be used when required to supplement power generation and assist in peak shaving. Alternatively, other chemicals could be synthesized from the same source via the indirect methods described above. Plants could furthermore be configured to produce power for export besides FT or SNG products. Such facilities are referred to as co-generation facilities.

Since IGCC, SNG and CTL facilities all rely on coal gasification as a first step, they all have the potential to provide hydrogen as a co-product, which can be extracted from the produced syngas stream. When large quantities of hydrogen are to be withdrawn, the ratio of hydrogen to carbon monoxide will need to be adjusted to still meet the required specifications for the other processes for converting syngas to liquid fuels.

III. The Preference for Indirect Coal Liquefaction via Fischer-Tropsch

Process economics for liquefaction have improved considerably over the last three decades. Lower production costs and higher distillate yields have resulted from better engineering design, more effective use of catalysts, and modified process concepts. This has permitted closer control over process performance, including a lessening in the severity of operating conditions (temperature and pressure), more efficient hydrogen utilization and increased liquid or gas yields. As such, current CTL processes are capable of producing a slate of premium products in the range of $50-55/bbl. A detailed comparison of direct and indirect coal liquefaction processes is beyond the scope of this paper; interested readers are referred to the open literature. A qualitative comparison is given in Table 1 below.

Table 1. Comparison of Direct and Indirect Liquefaction

Characteristic	Direct CTL	Indirect CTL
Commercial Experience/ Economics	Commercially elusive; not yet proven; limited experience; higher capital costs.	Commercially proven/made up of proven modules; more experience; lower capital cost.
Coal Feed	Uses selected coals – low ash, high reactivity.	Any gasifiable coal is acceptable with attention to HC ratio.
Plant Efficiencies and Environmental Performance	Higher thermal efficiency; environmentally marginal.	Lower thermal efficiency; total efficiency comparable to direct; environmentally superior.
Fuel Quality and Environmental Performance	Aromatic/cyclic products; potential carcinogens; fuels less favorable for priority pollutants and GHG's; diesel fraction - low cetane.	Paraffinic/olefinic products; naphtha low octane but excellent cracker feed; waxes converted to high quality lubes; fuels superior; diesel fraction –high cetane.

With respect to coal-to-liquids technologies, at the present time, indirect liquefaction by Fischer-Tropsch synthesis appears to be the preferred route because of its greater commercial experience, lower capital cost, flexibility in coal feed, plant efficiency, environmental performance, and higher product quality for the end-use fuels and chemicals. The remainder of this report addresses CTL processes based on the indirect liquefaction approach via Fischer-Tropsch synthesis.

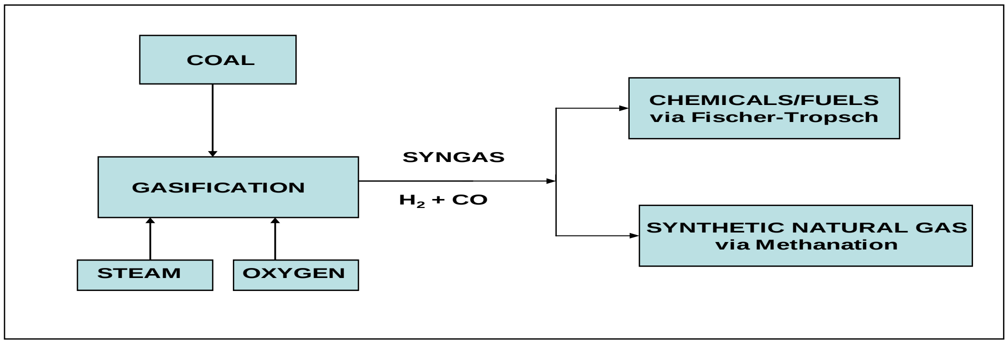
IV. Main Processing Steps for CTL and SNG

The schematic below shows the main processing steps for FT/CTL and SNG. In practice, such a facility would produce either FT liquid products or SNG (but not both), but the figure is simplified to illustrate the great degree of similarity for a large part of the plant.

The main unit processes in a coal-to-liquids (CTL) facility include gasification, gas cleaning or conditioning, gas conversion by FT synthesis , and product work-up (refining). For the production of Synthetic Natural Gas (SNG), syngas is also produced via the first step of gasification. It is then converted to methane in a methanation reactor and the product gas is adjusted to meet natural gas pipeline specifications. The plant complex in both cases would include ancillary systems for power generation, utilities, effluent treatment, ash disposal, some hydrogen separation capacity (for hydro-treating of FT products) and an air separation unit (ASU or oxygen plant). Environmental issues also need to be considered within the context of the total plant and facility

The main processing steps are discussed below.

Figure 1. Simplified Schematic of CTL and SNG



Coal Gasification

Gasification of coal involves the reaction of the hydrocarbons in the coal with steam and oxygen (or air) under conditions where there is insufficient oxygen present to lead to the combustion of the coal (technically a sub-stoichiometric reaction). This leads to the production of hydrogen and carbon monoxide as the principal products. The syngas can be then be used for a variety of uses such as for power generation (IGCC), or the production of SNG or FT coal-derived liquid fuels.

Gasification has been practiced for more than 100 years and was the process to produce "town gas" or lean BTU gas for domestic and industrial use in many countries before natural gas became common. Modern day gasifiers are very different from earlier gasifiers, although the basic process chemistry is similar. There are more than 100 types and configurations of gasifiers but few are commercially used at a meaningful capacity. Suffice it to state that the USA is lagging behind other coal countries in its use of gasification, primarily due to the availability of natural gas. South Africa is leading the world in gasification capacity (predominantly used for its FT CTL facilities), but there are estimated to be about 385 companies (plants) with about 500 individual gasifier units in operation world wide. Many of these are smaller units in China, where the syngas is used to generate hydrogen for fertilizer production.

An excellent and extensive reference work was published in 2004 under the title "Gasification" (Editors M. Van der Burgt and C. Higman, Elsevier). The interested reader is referred to this work for detailed process descriptions and comparisons between the various gasification technologies in commercial practice as well as those in development. Another valuable source of information is the web site of the Gasification Technologies Council (GTC) at www.gasification.org. This Council represents about 100 member institutions with an active interest in gasification.

Fischer-Tropsch Synthesis

The Fischer-Tropsch technology has been known and researched for more than eight decades and the literature in this regard is far beyond the scope of this report. Some of the historical aspects of the history and commercialization of FT are well covered in the *The American Energy Security Study* (http://www.americanenergysecurity.org/studyrelease.html.). Only a brief summary of the science and engineering underpinning the technology will be presented here.

- **Reactions.** A multitude of reactions take place during FT synthesis and one of the notable characteristics is that it produces hydrocarbon components with one carbon atom (methane) up to hundreds of carbon atoms, like some very hard waxes. Although this spectrum of products can be tailored within certain ranges, it is not possible to only make one or very few products. For fuels, this is not necessarily a draw-back since both gasoline (lighter or lower number of carbon atom-components) and diesel (heavier components) contain a large number of chemical species. Moreover, since there is carbon monoxide in the feed syngas, some of the oxygen in the carbon monoxide is incorporated into the products, leading to compounds such as alcohols, ketones and aldehydes (oxygenates) in modest quantities. Also these can be tailored, but only to a limited extent. Co-products from the FT synthesis include water and carbon dioxide. The latter can be minimized, based on feed gas composition and operating conditions. Therefore an FT plant needs extensive refinery-type facilities to produce the desired products at specification as demanded by the commercial market. One of the characteristics of the FT chemistry is that the reactions are very exothermic. This means that a large amount of heat is liberated during the reaction and this has to be removed in practice to prevent over-heating.

- **Catalysts.** There are two main types of FT catalysts. One is cobalt and the other iron. Both operate successfully commercially in different applications. Besides the difference in cost (cobalt is more expensive but lasts longer), there are differences in the details of the product spectra produced. A common requirement for these catalysts is that the feed gas cannot contain any sulfur (down to parts per billion is required), to avoid irreversible poisoning of the catalyst. Sulfur is therefore quantitatively removed in the syngas cleaning phase after gasification. This leads to sulfur free products.

- **Process Conditions.** There are two main categories of FT processes: high temperature FT (about 550 degrees F) and low temperature FT (about 400 degrees F). The former can only be operated using an iron catalyst (cobalt produces excessive amounts of methane at these temperatures) and the latter can use either iron or cobalt. Products from the high temperature FT have fewer carbon atoms in the molecules, contain more oxygenates and have more branching in the carbon skeleton of the produced molecules than the low temperature systems. This leads to improved gasoline quality and the large Sasol plants in South Africa produce about 160,000 bbl/day of fuels and chemicals based on this route. The low temperature routes produce longer carbon chain molecules and less oxygenates. The number of carbon atoms in the spectrum is higher that for the High temperature FT. This leads to a good quality diesel and the products which are heavier than diesel can be readily converted to diesel by a process called hydro cracking. Diesel for low temperature FT is of superior quality as compared with crude oil derived products. The pressures at which the commercial FT plants (both CTL and GTL) operate are typically 300 to 450 psi.

Chapter 3: Technical and Economic Evaluation of CTL and SNG using Kentucky Coals *(The Mitretek Report)*

This section addresses:

1. A detailed evaluation of CTL and SNG technologies suitable for Kentucky coals.
2. Comparative economics of capital, operating and other costs on a crude oil barrel equivalent.

I. Introduction

The Governor's Office of Energy Policy initiated a Memorandum of Agreement with the University of Kentucky Center for Applied Energy Research under which CAER would provide a description of the technical and economic assessment of technologies for producing transportation fuels, synthetic natural gas, chemicals and electricity from the gasification of coal, specifically Kentucky coals.

Mitretek Systems was asked to assist CAER in this work. Mitretek Systems made use of its in-house computer models to assess a number of coal conversion systems for the production of Fischer-Tropsch (FT) liquid fuels and SNG. Theses models provide an estimate of the performance and economics of commercial scale plants to produce FT fuels and SNG from specified Kentucky coals. The following represents the results of Mitretek's feasibility study.

II. CTL Case Studies

A total of 6 CTL cases were analyzed in this study. The description of these cases is given in Table 2. In this report two coal types - Eastern Kentucky and Western Kentucky bituminous coal - have been used as feedstocks for conceptual Fischer-Tropsch (FT) CTL facilities.

Table 2: Coal-to-Liquids Case Studies

Case Number	Capacity (BPD)	Configuration	Coal Type
1	10,000	No carbon capture	Eastern Kentucky
2	10,000	No carbon capture, yield sensitivity	Eastern Kentucky
3	10,000	No carbon capture	Western Kentucky
4	10,000	No carbon capture, yield sensitivity	Western Kentucky
5	10,000	Carbon capture	Eastern Kentucky
6	10,000	Carbon capture, yield sensitivity	Eastern Kentucky

In cases 1 through 4, carbon dioxide is vented to the atmosphere, while in cases 5 and 6, carbon dioxide is collected and compressed to 2,000 psi for sequestration. Cases 2, 4, and 6 were done to establish the sensitivity of the results to the naphtha yield from the FT reactor.

Feedstock Analysis for CTL Cases

The Western Kentucky and Eastern Kentucky coal analyses are shown in Tables 3 and 4, respectively.

Table 3. Western Kentucky Coal Analysis

	DRY	AR	MAF
C	69.93	63.65	80.73
H	4.71	4.29	5.44
N	1.39	1.27	1.60
CL	0.14	0.13	0.16
S	3.7	3.37	4.27
O	6.7	6.10	7.73
ASH	13.38	12.18	15.45
Moisture	99.95	8.98 99.95	0.00 115.39
BTU/#(HHV)	12715	11573	14679

Table 4. Eastern Kentucky Coal Analysis

	DRY	AR	MAF
C	74.27	69.91	83.13
H	4.86	4.57	5.44
N	1.48	1.39	1.66
CL	0.092	0.09	0.10
S	0.82	0.77	0.92
O	7.6	7.15	8.51
ASH	10.66	10.03	11.93
Moisture	99.782	5.87 99.79	0.00 111.69
BTU/#(HHV)	13366	12581	14961

Conceptual CTL Plant Process Units

The plant layout is estimated to require an approximate plot size of 2,556 x 2,500 feet or 150 acres. This includes key process units such as the gasification island, gas treatment, FT synthesis, and the power block as well as coal storage, transfer, and grinding. All offsites and utilities, exclusive coal conveying to the plant, roads and water wells and piping are also accounted for.

The total footprint of the facility including coal conveying, rail spur for product shipment, roads, water wells, and pipelines to the plant is expected to be about 200 acres.

Plant staffing is estimated to total about 190. This includes about 25 professionals and 115 operators, with the remainder being administrative, security, and maintenance labor. These CTL plants require approximately 5,000 TPD of Kentucky coal. [Assuming an average annual productivity of about 7,500 tons per man, a 10,000 BPD plant would result in employment of about 240 miners. Meeting the coal requirements of larger 30,000, 60,000 and 100,000 BPD plants would result in employment of about 730, 1460 and 2425 miners, respectively].

Regardless of size, overall configuration, and feedstock, the CTL conceptual plants analyzed in this study all have essentially the same process units in common. These are shown in the block flow diagrams in Figures 2, 3, and 4. The following describes the overall function of these individual process operations.

- **Coal Preparation.** For both Eastern and Western Kentucky coals, the coal is crushed and ground to a pulverized size distribution just prior to combination with water to form a slurry feed.

- **Coal Slurry.** In all six cases, coal is ground and combined with water to create a coal-slurry. The coal-slurry is pumped at high pressure into single-stage, slurry-feed gasifiers. The solids content of the coal-slurry is typically 65-70 percent, by weight.

- **The Air Separation Unit.** The oxygen for coal gasification is provided by an air separation unit (ASU). This design uses a conventional cryogenic ASU for production of 95 percent purity oxygen for coal gasification and of nitrogen for inert gas uses. For the SNG cases higher purity oxygen of 99.5 percent is necessary to meet the SNG pipeline specifications.

- **Gasification.** In all six cases, a single stage, slurry feed gasifier with quench was used. The coal is wet-milled to a size of about 100 microns before being combined with water to form a coal-water slurry. The slurry is fed to the gasifier with oxygen from an ASU. Gasification takes place at slagging temperatures, typically about 2,600 F and 450 psia. The carbon conversion in this gasifier is typically about 98 percent. In the quench system, the hot syngas leaves the bottom of the gasifier along with liquid ash and enters a water quench chamber. The quench removes hydrogen chloride and particulate matter before further processing of the syngas.

- **Gas Cooling, Raw Water Gas Shift, Carbonyl Sulfide Hydrolysis, and Mercury Removal.** The treatment scheme for the syngas produced in all six cases is the same. The synthesis gas stream leaving the gasifier quench section is split, and a portion of the stream is sent to a raw water gas shift reactor to adjust the hydrogen to carbon monoxide molar ratio to that required for the FT reactors. The other portion of the synthesis gas is sent to a carbonyl sulfide hydrolysis unit where the COS is hydrolyzed to hydrogen sulfide. The two streams, having a molar hydrogen to carbon monoxide ratio of about 1.0, are then combined and both streams are then cooled in gas coolers before being sent to activated carbon filtration for removal of mercury. This cooled gas is then sent to a two-stage Acid Gas Removal (AGR) unit for removal of hydrogen sulfide and carbon dioxide.

- **Acid Gas Removal.** The raw synthesis gas at about 400 psi from mercury removal is sent to an AGR unit. The AGR unit selected is used for the selective removal of hydrogen sulfide and for bulk removal of carbon dioxide. The acid gas produced by this selective absorption is suitable for feeding to a Claus-type unit for acid gas treatment (AGT) and recovery of elemental sulfur.

- **Hydrogen Recovery.** A portion of the clean synthesis gas leaving the AGR unit is sent to the hydrogen recovery unit where sufficient hydrogen is separated and purified for use in the FT upgrading section of the plant. This hydrogen is required for hydrotreating and hydrocracking. The hydrogen separation system chosen for this study is a combination of membranes and Pressure Swing Adsorption (PSA). The membrane system is used to avoid a pressure drop in the main synthesis gas stream. The final purification of the hydrogen is achieved by sending the permeate stream from the membrane unit to a PSA unit. Here the hydrogen is produced at 99.99 percent purity. The hydrogen leaves the PSA at essentially feed pressure while the PSA purge gases leave at essentially atmospheric pressure.

- **Sulfur Polishing.** Depending on operating conditions, the synthesis gas exiting the AGR unit still contains about 1-2 ppmv H2S. This quantity of H2S is still too great to feed to the sulfur sensitive iron-based catalysts in the Fischer-Tropsch synthesis process. To remove this residual H2S, zinc oxide polishing reactors are used. The zinc oxide reacts with the hydrogen sulfide to form solid zinc sulfide. The product gas leaving the polishing reactor contains less than 0.03 ppmv H2S.

- **Fischer-Tropsch Synthesis.** The clean synthesis gas containing less than .03 ppmv H2S from the sulfur polishing reactor is sent to the FT section of the plant. At the required product production rates used in this study, multiple trains of slurry phase reactors are needed to process the clean synthesis gas. The synthesis gas is heated to about 400ºF and fed to the bottom of the FT reactors. The gas bubbles up through the reactors that are filled with liquid hydrocarbons in which are suspended fine iron-based catalyst particles. Reaction heat is removed via heat exchangers suspended in the reactors. The liquid medium enables rapid heat transfer to the heat exchangers which allows high synthesis gas conversions in a single pass through the reactor. Synthesis gas conversions of about 75-80 percent per pass can be obtained.

  Volatile overhead product swept from the reactors is separated in hot and cold separators to recover liquid hydrocarbons. Complete conversion of the synthesis gas to hydrocarbons does not occur in one pass through the FT reactors. In the simple recycle configuration used in all six cases in this study, the effluent from the FT reactors is cooled to recover the portion constituting liquid fuels and the unconverted synthesis gas is recycled back to the FT reactors to increase the conversion to fuels. The carbon dioxide produced in synthesis is removed in the recycle loop. Heavy product that is non-volatile under reaction conditions is removed from the reactor and separated from the catalyst. The raw FT products consisting of crude naphtha, crude middle distillate, and crude wax are sent directly to product upgrading. Fresh FT catalyst is activated in a separate catalyst activation reactor and then added on-line to the FT reactors to replace spent catalyst and to maintain overall activity. The catalyst replacement rate assumed in this study is 0.5 pounds per barrel of FT product.

- **FT Product Upgrading.** The raw FT products need to be upgraded to produce naphtha and high quality diesel fuel. The raw naphtha and middle distillate are sent to a hydrotreating unit to saturate the olefins that are produced in the FT process. The wax material is sent to a hydrocracker where the wax is converted into hydrocarbon gases, naphtha and diesel fuel.

- **Carbon Dioxide Removal in Recycle Loop.** The FT tail gas containing light hydrocarbon gases, unconverted hydrogen and carbon monoxide, some nitrogen, and carbon dioxide is split into two streams. One stream is recycled back to the FT unit to increase liquids yield and the other stream is sent to the power generation block. The recycled tail gas is processed in an amine unit to remove the carbon dioxide that is inert and takes up space in the slurry FT reactors. This is a standard MDEA unit with a single carbon dioxide absorber and solvent regenerator.

- **Power Generation Block.** The FT tail gas that is not recycled back to the FT reactors is sent to a gas turbine where electric power is generated. The hot effluent gas from the gas turbine is sent to the heat recovery steam generator (HRSG).

  High temperature flue gas exiting the gas turbine is sent to the HRSG to recover the large quantity of thermal energy as steam for the steam turbines. The HRSG is a multi-chamber, multi-pressure design that is matched to the characteristics of the gas turbine exhaust. The HRSG chamber pressures are typically 1,800 psia and 450 psia for the high pressure and intermediate pressure steam turbine sections, respectively. In addition to generating and superheating steam, the HRSG reheats steam released from the high pressure steam turbine and provides condensate and feedwater heating and pre-heating.
  The steam turbine consists of a high pressure section (~1,800 psig, 1,050 F), an intermediate pressure section (~ 400 psig, 1,050 F), and a low pressure section. All three sections are connected mechanically to an electric power generator by a common shaft.

- **Balance of Plant (BOP) Units.**

  Product storage:
  Storage tanks are on site for storing naphtha and diesel fuels.
  Water systems:
  Systems are provided for cooling towers, to prepare boiler feed water (BFW), waste water treating, storm water handling, and fire water systems.
  Electrical transformers and plant power distribution facilities are provided.
  Instrumentation and Controls:
  Unit operations instrumentation and control systems are provided.

Technical Description of CTL Cases Analyzed

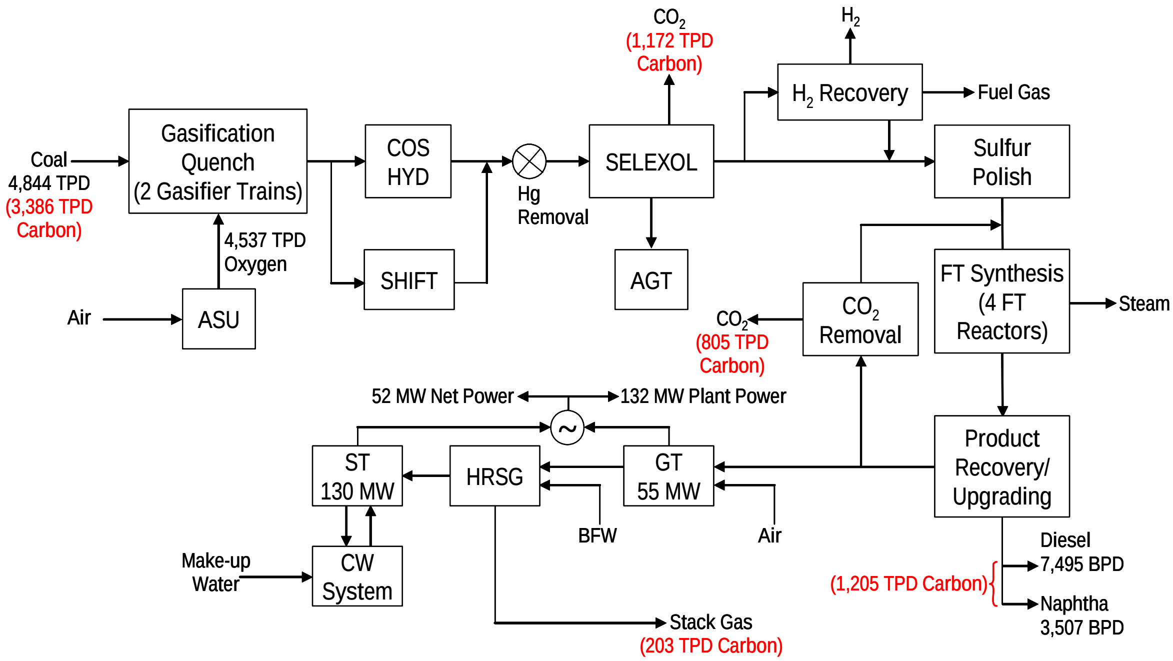
- **CASE 1: 10,000 BPD Eastern Kentucky Coal, No Carbon Capture.** Figure 2 shows a block flow diagram for Case 1. This system produces 10,000 barrels per day on an equivalent diesel basis of naphtha and diesel. It uses Eastern Kentucky coal as feed material to two trains of single stage, slurry feed gasifiers. The configuration used is simple recycle system and the clean syngas is sent to four (4) FT synthesis reactor trains. Each FT reactor produces about 2,500 BPD of product.

  The as-fed coal input to the plant is 4,844 TPD. The products from this plant configuration are 3,507 BPD of FT naphtha, 7,495 BPD of FT diesel, and 184 MW of gross power. The total plant parasitic power is estimated to be 132 MW; therefore, the net power available for sale is only 52 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 50.8 percent.

- **CASE 2: 10,000 BPD Eastern Kentucky Coal, No Carbon Capture, FT Reactor Yield Sensitivity.** The process arrangement for this case is identical to that shown in Figure 2. In this case, however, the yield of diesel from the FT reactor has been adjusted to determine the systems' sensitivity to FT reactor conditions, operations and catalyst. The diesel yield in this case is based on product selectivity similar to that reported by Rentech, Inc. in Denver, Colorado. The FT reactor used by Rentech is reported to have higher yields of diesel than previous commercial FT reactor systems. This system produces 10,000 barrels per day on an equivalent diesel basis of naphtha and diesel with a higher ratio of diesel to naphtha than Case 1.

  The as-fed coal input to the plant is again 4,844 TPD. The products from this plant configuration are 2,013 BPD of FT naphtha, 8,886 BPD of FT diesel, and 184 MW of gross power. The total plant parasitic power is estimated to be 132 MW therefore the net power available for sale is 52 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 50.8 percent.

Figure 2. Case 1 - 10,000 BPD, East Kentucky Bituminous Coal



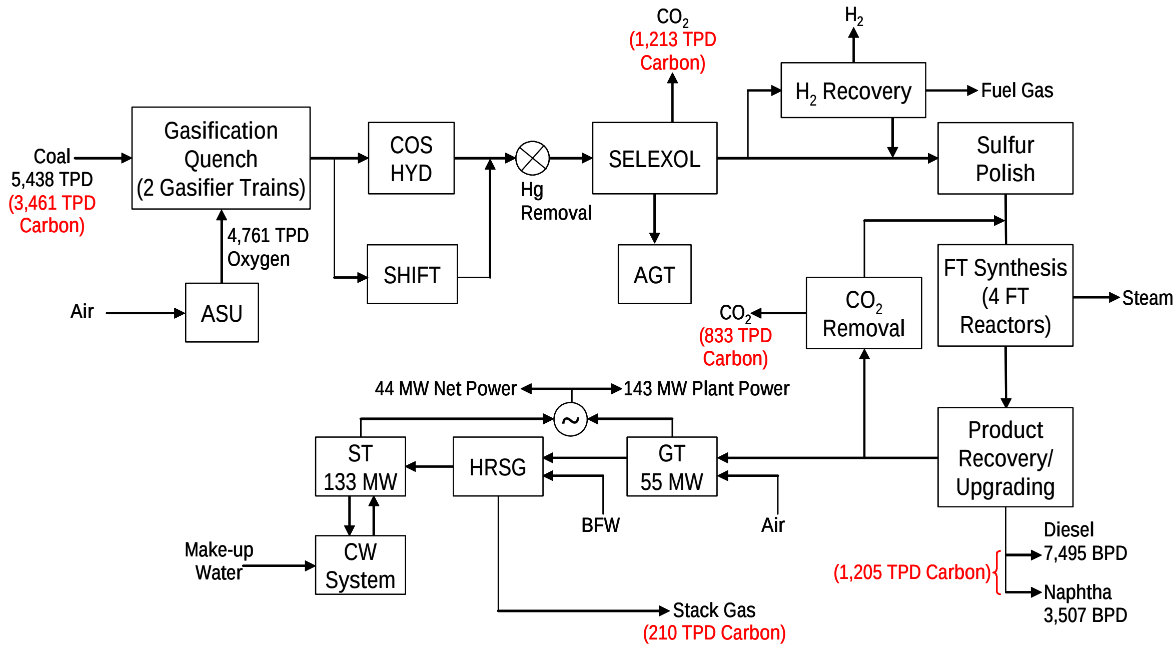
- **CASE 3: 10,000 BPD Western Kentucky Coal, No Carbon Capture.** Figure 3 shows a block flow diagram for Case 3. This system produces 10,000 barrels per day on an equivalent diesel basis of naphtha and diesel. It uses Western Kentucky coal as feed material to two trains of single stage, slurry feed gasifiers and has a simple recycle configuration. Again, the clean syngas is sent to four (4) FT synthesis reactor trains. Each FT reactor can produce about 2,500 BPD of products.

  The as-fed coal input to the plant is 5,438 TPD. The products from this plant configuration are 3,507 BPD of FT naphtha, 7,495 BPD of FT diesel, and 187 MW of gross power. The total plant parasitic power is estimated to be 143 MW therefore the net power available for sale is 44 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 48.7 percent.

- **CASE 4: 10,000 BPD Western Kentucky Coal, No Carbon Capture, FT Reactor Yield Sensitivity.** The process arrangement for this case is identical to that shown in Figure 3. In this case, however, the yield of diesel from the FT reactor has been adjusted to determine the systems' sensitivity to FT reactor conditions. The diesel yield in this case is based on results similar to those reported by Rentech. This system produces 10,325 barrels per day on an equivalent diesel basis of naphtha and diesel with a higher ratio of diesel to naphtha than in case 3.

  The as-fed coal input to the plant is 5,438 TPD. The products from this plant configuration are 2,013 BPD of FT naphtha, 8,886 BPD of FT diesel, and 187 MW of gross power. The total plant parasitic power is estimated to be 143 MW therefore the net power available for sale is 44 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 48.6 percent.

Figure 3. Case 3 - 10,000 BPD, West Kentucky Bituminous Coal



- **CASE 5: 10,000 BPD Eastern Kentucky Coal with Carbon Capture.** The process arrangement for this case is shown in Figure 4. In this case the carbon dioxide from the Selexol unit and the FT recycle loop is collected and compressed to 2,000 psi for subsequent sequestration. This system produces 10,000 barrels per day on an equivalent diesel basis of naphtha and diesel. It uses Eastern Kentucky coal as feed material to two trains of single stage, slurry feed gasifiers and has a simple recycle stream to four (4) FT synthesis reactor trains.

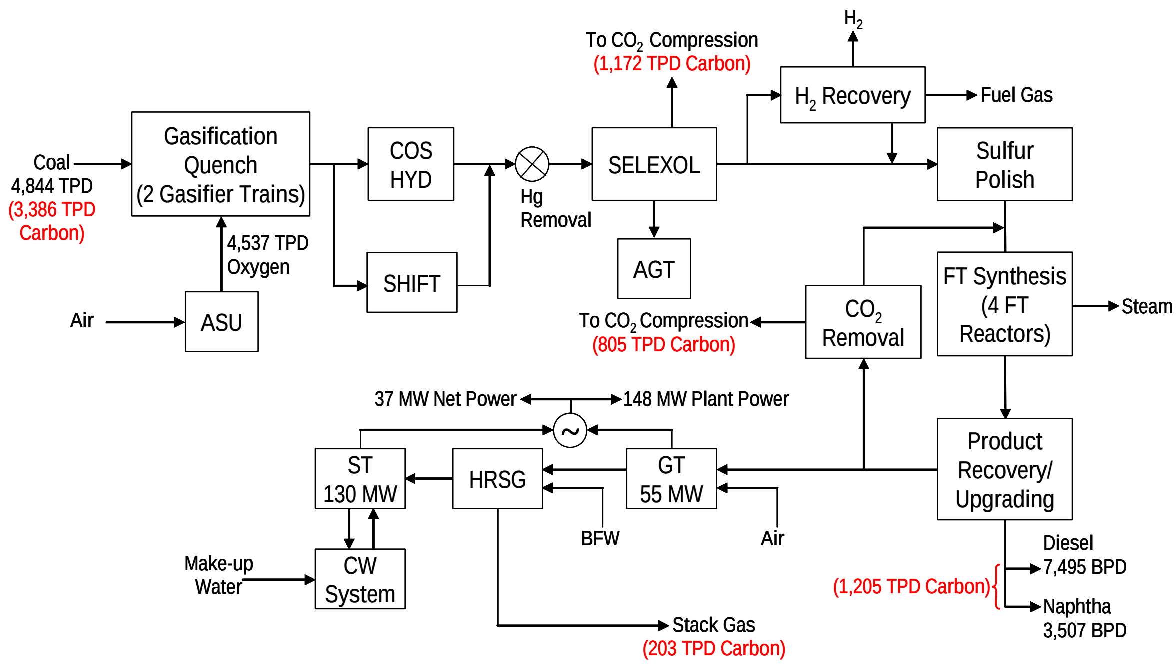
  The as-fed coal input to the plant is 4,844 TPD. The products from this plant configuration are 3,507 BPD of FT naphtha, 7,495 BPD of FT diesel, and 185 MW of gross power. The total plant parasitic power is estimated to be 148 MW therefore the net power available for sale is 37 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 49.8 percent.

  Referring to Figure 4 it can be seen that of the 3,386 TPD of carbon entering the plant with the coal, 1,205 TPD is contained in the liquid fuels product. In the Selexol unit 1,172 TPD of carbon is removed and another 805 TPD of carbon is removed from the FT recycle stream. Only 203 TPD of carbon is emitted from the stack. This represents about 90 percent carbon removal.

- **CASE 6: 10,000 BPD Eastern Kentucky Coal with Carbon Capture, FT Reactor Yield Sensitivity.** The process arrangement for this case is identical to that shown in case 5. In this case, however, the yield of diesel from the FT reactor has been adjusted to determine the systems' sensitivity to a higher diesel make. The diesel yield in this case is based on results similar to those reported by Rentech. This system produces 10,000 barrels per day on an equivalent diesel basis of naphtha and diesel with a higher ratio of diesel to naphtha than in case 5.

The as-fed coal input to the plant is 4,844 TPD. The products from this plant configuration are 2,013 BPD of FT naphtha, 8,887 BPD of FT diesel, and 185 MW of gross power. The total plant parasitic power is estimated to be 148 MW therefore the net power available for sale is 37 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 49.6 percent.

Figure 4. Case 5 - 10,000 BPD, East Kentucky Bituminous Coal, with CO_2 Capture



Economics of CTL Cases Analyzed

Table 5 summarizes the capital equipment costs for the six Kentucky coal cases analyzed in this study. For convenience the capital costs are disaggregated into major plant sections. Costs for many of the process units in these CTL plants were derived from a recent study commissioned by the National Energy Technology Laboratory. That study included an updated techno-economic analysis of Integrated Coal Gasification Combined Cycle (IGCC) plants of a similar size to the CTL plants analyzed in this study. IGCC plants contain many unit operations common to CTL including coal gasification, synthesis gas cleaning, air separation, gas and steam turbines and heat recovery steam generators. The costs of other units specific to CTL, including Fischer-Tropsch synthesis and upgrading, were obtained from other sources.

Coal and sorbent handling refers to all equipment associated with the storage, reclaiming, conveying, crushing and sampling of coal. The gasification section includes the coal feed, the gasifiers, quench system, and slag removal. The air separation unit (ASU) is a standard cryogenic system for separation of oxygen and nitrogen. The syngas cleanup system contains several components that remove hydrogen sulfide, carbonyl sulfide, cyanide, ammonia, particulates, mercury, and carbon dioxide. It also includes acid gas treatment, sulfur recovery, hydrogen recovery and water gas shift. The carbon dioxide capture section includes carbon dioxide removal and, in cases 5 and 6, carbon dioxide compression to 2,000 psi. The FT section includes the synthesis reactors, catalyst activation, FT product upgrading, and hydrocarbon recovery. The power block includes gas turbines, heat recovery steam generation, steam turbine, nitrogen compression, cooling water systems, feedwater and other plant water treatment systems, and the plant electrical and distribution system. The balance of plant includes product tankage, instrumentation and controls, site improvements, and buildings and structures.

Referring to Table 5 the total installed costs of the Kentucky coal plants vary from $745 million (MM) for cases 1 and 2 to $763 MM for the 10,000 BPD facilities in cases 3 and 4.

Table 5. Capital Equipment Costs (MM$) for Kentucky CTL Cases

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Plant Size	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Western KY Coal Without Carbon Capture**	**Western KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity With Carbon Capture**
Coal and Sorbent Handling	20	20	22	22	20	20
Coal and Sorbent Prep and Feed	34	34	37	37	34	34
Feedwater and Misc BOP Systems	25	25	26	26	25	25
Gasifier and Acc.	153	153	153	153	153	153
Air Separation and Compression	85	85	88	88	85	85
Syngas Cleaning and Shift	127	127	128	128	127	127
CO2 Removal and Compression	11	11	11	11	26	26
Combustion Turbine and Acc.	25	25	25	25	25	25
FT Synthesis	97	97	97	97	97	97
HRSG w/ducts and Stack	38	38	38	38	38	38
Steam Turbine and Acc.	24	24	25	25	24	24
Cooling Water System	26	26	26	26	26	26
Ash/Spent Sorbent Handling	29	29	36	36	29	29
Accessory Electrical Plant	12	12	12	12	12	12
Instrumentation and Control	15	15	15	15	15	15
Site Improvements	12	12	12	12	12	12
Buildings and Structures	12	12	12	12	12	12
Total Capital Equipment	**745**	**745**	**763**	**763**	**760**	**760**

Table 6 summarizes the additional capital requirements for these plants. This includes home office costs (mostly front end engineering and design, i.e.: FEED, and detailed engineering design), process and project contingency, license, financing and legal fees, and non-depreciable capital. An overall project contingency of 5 percent has been applied to all of the cases to reflect the level of project definition for this non-site specific feasibility analysis. The total capital requirements varied with plant size from $966 MM in cases 1 and 2 to $988 for the 10,000 BPD plant in cases 3 and 4.

Table 6. Additional Capital Costs (MM$) for Kentucky CTL Cases

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Plant Size	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Western KY Coal Without Carbon Capture**	**Western KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity With Carbon Capture**
Home Office	63	63	65	65	65	65
Process Contingency	34	34	34	34	36	36
Project Contingency	42	42	43	43	43	43
License Fees	25	25	25	25	25	25
Financing/ Legal	25	25	25	25	25	25
Non-depreciable Capital	32	32	33	33	32	32
Total Capital Equipment	745	745	763	763	760	760
Total Capital Requirement	**966**	**966**	**988**	**988**	**986**	**986**

Table 7 summarizes the annual operating costs for these Kentucky coal CTL plants. Fixed operating costs include royalties, labor and overhead, administrative labor, local taxes and insurance, and maintenance materials. Variable operating costs include coal feed cost considered to be $35/ton for the Eastern Kentucky coal and $30 per ton for the lower quality Western Kentucky coal, catalyst, water and chemicals, and other which is primarily solids disposal costs. The by product credit refers to sales of recovered sulfur. Net annual operating costs vary from $117 MM for cases 1, 2, 5, and 6 to $112 MM for cases 3 and 4. There are no purchases of electricity because all power required is generated on site. The small quantities of natural gas required for start up are not included.

Table 7. Annual Operating Costs (MM$) for Kentucky CTL Cases

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Plant Size	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Western KY Coal Without Carbon Capture**	**Western KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity With Carbon Capture**
Royalties	4	4	4	4	4	4
Coal feed	55.69	55.69	53.59	53.59	55.69	55.69
Catalyst/ Chemicals	8	8	8	8	8	8
Labor/ Overhead	18	18	18	18	18	18
Administrative	3	3	3	3	3	3
Local Taxes & Insurance	18	18	19	19	18	18
Maintenance & Materials	8	8	8	8	8	8
Other Operating Costs	3	3	3	3	3	3
Gross Annual Op Costs	117.7	117.7	116.6	116.6	117.7	117.7
Byproduct Credit	1	1	5	5	1	1
Net Annual Op Costs	**116.7**	**116.7**	**111.6**	**111.6**	**116.7**	**116.7**

Table 8 summarizes the overall inputs of coal and outputs of fuels and electric power from the Kentucky CTL plants. Also included on this table are the estimated plant parasitic power, gross power, sulfur recovered, estimated SOx and NOx emissions, and carbon dioxide released/captured. The overall thermal inputs and outputs from the plants allow the overall efficiency to be determined. The overall system efficiencies varied from 49 to 51 percent with cases 1 and 2 using Eastern KY coal having the highest efficiency and cases 3 and 4 the lowest.

Coal feed varies from 4,844 TPD for the Eastern Kentucky coals in cases 1, 2, 5, and 6 to 5,438 TPD in the Western Kentucky coal cases 3 and 4. Equivalent diesel is calculated by assuming that the naphtha product has a value of 71 percent compared to the diesel fraction. The diesel is the more valuable product since it has zero sulfur and a cetane number of about 75, whereas the naphtha, being predominantly paraffinic, has a low octane number. This naphtha could be used as a zero sulfur blending stock with petroleum naphtha for gasoline or it is an excellent cracker feed for ethylene production.

Table 8. Inputs and Outputs for Kentucky CTL Cases

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Plant Size	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**	**10,000 BPD**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Western KY Coal Without Carbon Capture**	**Western KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity With Carbon Capture**
Coal feed (TPD as received)	4,844	4,844	5,438	5,438	4,844	4,844
Naphtha (BPD)	3,507	2,013	3,507	2,013	3,507	2,013
Diesel (BPD)	7,495	8,886	7,495	8,886	7,495	8,887
Naphtha & Diesel (BPD)	11,002	10,899	11,002	11,002	11,002	10,900
Equivalent Diesel (BPD)	10,000	10,324	10,000	10,325	10,000	10,295
Net Power Sales (MWe)	52	52	44	44	37	37
Gross Power (MWe)	184	184	187	187	185	185
Parasitic Power (MWe)	132	132	143	143	148	148
Sulfur (TPD)	37	37	180	180	37	37
CO_2 captured (TPD)	0	0	0	0	7,249	7,249
CO_2 released (TPD)	7,990	7,990	8,272	8,272	744	744
SOx (TPD)	0.007	0.007	0.031	0.031	0.007	0.007
NOx (TPD) Dry @ 15 % O_2	0.462	0.462	0.463	0.463	0.462	0.462
Coal HHV (MMBtu/D)	121,885	121,885	125,868	125,868	121,885	121,885
Products HHV (MMBtu/D)	61,936	61,866	61,281	61,216	60,707	60,483
Overall Efficiency (HHV)	50.8 %	50.8 %	48.7 %	48.6 %	49.8 %	49.6 %

Table 9 summarizes the economics for each of the six cases. The capital cost of these plants in terms of capital dollars per daily barrel (DB) of fuels produced varies from a low of $87,814/DB in case 1 to $90,711/DB in case 6. The RSP on a crude oil equivalent varies from a low of $49.96/B in Case 4 to a high of $53.20/B in case 5 (Eastern coal with carbon capture). The RSP was calculated using a discounted cash flow analysis with the economic assumptions shown in Table 10. [For larger scale CTL plants, economies of scale bring down costs or RSP to $45.50, $44.00 and $43.00 per barrel for 30,000, 60,000 and 100,000 BPD plants, respectively.]

Table 9. Economic Summary of Kentucky CTL Cases

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Plant Size	**10,000 BPD**	**10,324 BPD**	**10,000 BPD**	**10,325 BPD**	**10,000 BPD**	**10,295 BPD**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Western KY Coal Without Carbon Capture**	**Western KY Coal FT Reactor Yield Sensitivity Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Eastern KY Coal FT Reactor Yield Sensitivity With Carbon Capture**
Capital ($/DB)	87,814	88,644	89,733	90,637	89,623	90,711
Capital	36.06	34.93	36.84	35.69	36.80	35.74
O&M	18.57	17.99	17.66	17.10	18.57	18.04
Coal	16.95	16.42	16.31	15.80	16.95	16.47
Power Credit	4.44	4.30	3.76	3.64	3.16	3.07
Total	67.13	65.03	67.05	64.94	69.16	67.18
RSP ($/B COE)	51.64	50.02	51.58	49.96	53.20	51.68

COE – Crude Oil Equivalent
$/DB – dollars per daily barrel
RSP– required selling price

Table 10. Parameters and Assumptions Used in Economic Analysis of CTL

Economic Parameter / Assumption	Value
Construction Period	3 years
Incurred Capital Cost Construction Year 1	20%
Incurred Capital Cost Construction Year 2	50%
Incurred Capital Cost Construction Year 3	30%
1st Year Availability	45%
2nd Year Availability	81%
3rd Year and Beyond Availability	90%
Plant Lifetime	25 years
Return on Equity	15%
Depreciation Method	Double declining balance (16 years)
Debt: Equity Ratio	67:33
Interest Rate	8%
Inflation Rate	3%
Tax Rate	40%
Sulfur Price	$80 per ton
Naphtha Value	0.714 times diesel value
Eastern Kentucky Coal Price	$35 per ton
Western Kentucky Coal Price	$30 per ton

FT Reactor Yield Sensitivities for CTL Cases

There are reported differences in the product slate when using slurry phase FT synthesis with iron catalysts. Yields of naphtha, the less valuable FT product, can range between a high of about 30 percent to below 20 volume percent. Because of this it was decided to explore the sensitivity to this range in this analysis. Table 9 also indicates the improvement - i.e., reduction - in the diesel and

COE RSP's when the FT reactor diesel yield is increased relative to the naphtha yield in cases 2, 4, and 6. When this is done, because of the higher value of the diesel, the typical reduction in the diesel RSP is approximately 3 percent. In case 1 the diesel RSP is $51.64/B and this is reduced to $50.02/B when the reactor diesel yield is increased.

Water Use for CTL Cases

Table 11 summarizes the estimated water balance for case 1. Water use in the remaining five cases is not expected to be significantly different given the overall similarities in plant configurations. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of hydrogen in the syngas. The cooling water system (mechanical draft cooling towers) is by far the largest consumer of water, followed by the water lost in the flue gas.

The raw water flow of 2,224 gallons per minute represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. With a fuel product rate of 11,002 barrels per day and 42 gallons per barrel, the total make-up water requirement for the Kentucky coal cases reviewed in this study are therefore estimated to be about 7 barrels of water per barrel of liquid fuels product.

Table 11. Kentucky Coal CTL Facility Water Balance for Case 1

Water In	Flow	Water Out	Flow
Location	(gpm)	Location	(gpm)
Moisture in coal	47.4	Water lost in Gasification Shift	138.2
Combustion of H2 in the Gas Turbine	83.5	Ash handling blowdown	86.4
Moisture in air to the ASU	12.9	Water with slag	50.4
Moisture in air to the Gas Turbine	5.2	Water lost in WGS reaction	123.1
Raw water	2,224	Gas Turbine flue gas	273.4
		Sour water blowdown	54.2
		Cooling Tower drift	3.8
		Cooling Tower Evaporation	1,087
		Cooling Tower Blowdown	543.6
		Moisture in ASU vent	12.9
Total	**2,373**		**2,373**

Summary and Conclusions for CTL Cases

For the techno-economic assumptions and basis used in this study, the results summarized in Table 12 support the following conclusions:

- This feasibility study has shown that low-sulfur ultra clean diesel can be produced from Eastern and Western Kentucky coals using existing technologies for between $49.96 and $53.20 per barrel on a crude oil equivalent basis. This price is currently competitive with today's prices of crude oil and petroleum refined liquid fuel products. [For larger scale CTL plants, economies of scale bring down costs to $45.50, $44.00 and $43.00 per barrel for 30,000, 60,000 and 100,000 BPD plants, respectively.]

- For the economic assumptions and coal types used in this study, the most economically attractive configurations are to use Eastern and Western Kentucky coals with no carbon capture with low naphtha make. Eastern Kentucky coal is of higher quality than the Western Kentucky coal and this is reflected in the assumed coal cost of $35 per ton for the Eastern coal and $30 per ton for the Western coal.

- Annualized capital costs and operating costs (including coal cost) contribute approximately equally to the required selling price of the product.

- Reducing the naphtha to diesel ratio from the FT reactor improves the product quality and value thus reducing the RSP by about 3 percent compared to a higher naphtha to diesel ratio.

- When carbon capture is required there is a small efficiency penalty of about 2 percent and a cost of product penalty of about 3 percent. The efficiency penalty is small because, even in the cases where carbon capture is not required, the carbon dioxide still has to be removed. The only difference is that the carbon dioxide has to be compressed to 2000 psi when capturing for subsequent sequestration is necessary. This additional cost does not include the actual cost of sequestering this compressed carbon dioxide. Ideally this carbon dioxide could be used for enhanced oil recovery if there are suitable opportunities within a feasible distance from the plant.

- The water use requirements of the Kentucky CTL plants are at or below typical utility averages. If water availability is an issue the CTL plant could be redesigned for minimal water use by maximizing the use of air cooling. [Employing air cooling could reduce water usage significantly, which would otherwise be lost as cooling tower drift, evaporation and blowdown].

- It should be cautioned that this study is not a detailed engineering and economic analysis. It is a feasibility analysis using certain specified coal inputs to generic non site specific conceptual CTL plants. The technical performance of the plants is modeled in sufficient detail to have a high level of confidence in the overall product output, coal input, power and utilities consumption and hence overall efficiency. Because this analysis is at the feasibility level and non site specific, the accuracy of the construction cost estimates is expected to be about +/- 30 percent. However, although there is some uncertainty in the absolute costs, the cost differences between the cases are considered to be meaningful.

Table 12. Summary of Results for Kentucky CTL Cases

Case Number - Configuration	Equivalent Diesel Production (BPD)	Exported Power (MW)	Capital Require ($/DB)	Diesel RSP and Crude Oil Equivalent RSP ($/B)	Efficiency (% HHV)
1. Eastern KY Coal without Carbon Capture	10,000	52	87,814	67.13 51.64	50.8
2. Eastern KY Coal FT Reactor Yield Sensitivity w/o Carbon Capture	10,324	52	88,644	65.03 50.02	50.8
3. Western KY Coal without Carbon Capture	10,000	44	89,733	67.05 51.58	48.7
4. Western KY Coal FT Reactor Yield Sensitivity without Carbon Capture	10,325	44	90,573	64.94 49.96	48.6
5. Eastern KY Coal with Carbon Capture	10,000	37	89,623	69.16 53.20	49.8
6. Eastern KY Coal FT Reactor Yield Sensitivity with Carbon Capture	10,295	37	90,711	67.18 51.68	49.6

III. SNG Case Studies

A total of 3 SNG cases were analyzed in this study. The description of these cases is given in Table 13. In this report two coal types - Eastern Kentucky and Western Kentucky bituminous coal - have been used as feedstocks to conceptual SNG facilities. The plants were approximately the same size as the 10,000BPD CTL plant from the companion report. The three cases are:

1. A coal-derived SNG plant of size 74 MMscfd using an East Kentucky coal feedstock with no carbon capture.

2. A coal-derived SNG plant of size 74 MMscfd using an East Kentucky coal feedstock with carbon capture.

3. A coal-derived SNG plant of size plant 74 MMscfd using a West Kentucky coal feedstock with no carbon capture.

In cases 1 and 3, carbon dioxide is vented to the atmosphere while in case 2, carbon dioxide is collected and compressed to 2,000 psi for sequestration.

Table 13. SNG Case Studies

Case Number	SNG Produced (MMscfd)	Configuration	Coal Type
1	74	No carbon capture	Eastern Kentucky
2	74	Carbon capture	Eastern Kentucky
3	74	No carbon capture	Western Kentucky

Feedstock Analysis for SNG Cases

The Western Kentucky and Eastern Kentucky coal analyses are shown in Tables 14 and 15, respectively.

Table 14. Western Kentucky Coal Analysis

	DRY	AR	MAF
C	69.93	63.65	80.73
H	4.71	4.29	5.44
N	1.39	1.27	1.60
CL	0.14	0.13	0.16
S	3.7	3.37	4.27
O	6.7	6.10	7.73
ASH	13.38	12.18	15.45
Moisture	99.95	8.98 99.95	0.00 115.39
BTU/#(HHV)	12715	11573	14679

Table 15. Eastern Kentucky Coal Analysis

	DRY	AR	MAF
C	74.27	69.91	83.13
H	4.86	4.57	5.44
N	1.48	1.39	1.66
CL	0.092	0.09	0.10
S	0.82	0.77	0.92
O	7.6	7.15	8.51
ASH	10.66	10.03	11.93
Moisture	99.782	5.87 99.79	0.00 111.69
BTU/#(HHV)	13366	12581	14961

Conceptual SNG Plant Process Units

The plant layout is estimated to require an approximate plot size of 2,556 x 2,500 feet or 150 acres. This includes key process units such as the gasification island, gas treatment, methanation, and the power block as well as coal storage, transfer, and grinding. All offsites and utilities, exclusive of coal conveying to the plant, roads and water wells and piping are also accounted for. The total footprint of the facility including coal conveying, SNG distribution, roads, water wells, and pipelines to the plant is expected to be about 200 acres.

Plant staffing is estimated to total about 190. This includes about 25 professionals and 115 operators, with the remainder being administrative, security, and maintenance labor. These SNG plants require approximately 5,000 TPD of Kentucky coal. [Assuming an average annual productivity of about 7,500 tons per man, a 10,000 BPD plant would result in employment of about 240 miners. Meeting the coal requirements of larger 30,000, 60,000 and 100,000 BPD plants would result in employment of about 730, 1460 and 2425 miners, respectively]. It is estimated that about 700 to 1,000 maximum construction workers will be needed on site for plant construction.

Regardless of size, overall configuration, and feedstock, the SNG conceptual plants analyzed in this study all have essentially the same process units in common. These are shown in the block flow diagrams in Figures 5, 6, and 7. The following describes the overall function of these individual process operations.

- **Coal Preparation.** For both the Western and Eastern Kentucky coals, the coal is crushed and ground to a pulverized size distribution just prior to combination with water to form a slurry feed.

- **Coal Slurry.** In all three cases, coal is ground and combined with water to create a coal-slurry. The coal-slurry is pumped at high pressure into single-stage, slurry-feed gasifiers. The solids content of the coal-slurry is typically 65-70 percent, by weight.

- **The Air Separation Unit.** The oxygen for coal gasification is provided by an air separation unit (ASU). For the SNG cases, high purity oxygen of 99.5 percent is necessary to meet the SNG pipeline specifications.

- **Gasification.** In all three cases, a single stage, slurry feed gasifier with quench was used. The coal is wet-milled to a size of about 100 microns before being combined with water to form a coal-water slurry. The slurry is fed to the gasifier with oxygen from an ASU. Gasification takes place at slagging temperatures, typically about 2,600 F and 450 psia. The carbon conversion in this gasifier is typically about 98 percent. In the quench system, the hot syngas leaves the bottom of the gasifier along with liquid ash and enters a water quench chamber. The quench removes hydrogen chloride and particulate matter before further processing of the syngas.

- **Gas Cooling, Raw Water Gas Shift, Carbonyl Sulfide Hydrolysis, and Mercury Removal.** The treatment scheme for the syngas produced in all three cases is the same. The synthesis gas stream leaving the gasifier quench section is split, and a portion of the stream is sent to a raw water gas shift reactor to adjust the hydrogen to carbon monoxide molar ratio to that required for the methanation reactors. The other portion of the synthesis gas is sent to a carbonyl sulfide hydrolysis unit where the COS is hydrolyzed to hydrogen sulfide. The two streams, having a molar hydrogen to carbon monoxide ratio of just over 3, are then combined and both streams are then cooled in gas coolers before being sent to activated carbon filtration for removal of mercury. This cooled gas is then sent to a two-stage Acid Gas Removal (AGR) unit for removal of hydrogen sulfide and carbon dioxide.

- **Acid Gas Removal.** The raw synthesis gas at about 400 psi from mercury removal is sent to an AGR unit. The AGR unit selected is used for the selective removal of hydrogen sulfide and for bulk removal of carbon dioxide. The acid gas produced by this selective absorption is suitable for feeding to a Claus-type unit for acid gas treatment (AGT) and recovery of elemental sulfur.

- **Sulfur Polishing.** Depending on operating conditions, the synthesis gas exiting the AGR unit still contains about 1-2 ppmv H_2S. This quantity of H_2S is still too great to feed to the sulfur sensitive nickel catalysts in the methanation process. To remove this residual H_2S, zinc oxide polishing reactors are used. The zinc oxide reacts with the hydrogen sulfide to form solid zinc sulfide. The product gas leaving the polishing reactor contains less than 0.03 ppmv H_2S.

- **Methanation.** The clean synthesis gas from sulfur polishing is sent to the methanation section of the plant. The methanation process simulated in this analysis is based on the expected performance of the Haldor-Topsoe TREMP process. This is a high temperature methanation process that typically would use multiple reactors - four in series - that catalytically convert carbon monoxide (CO) and hydrogen (H_2) in the clean synthesis gas to methane (CH_4). The clean feed gas is mixed with recycle gas from the first stage to control the temperature rise and then sent to the first stage methanation. The methanation catalyst is a proprietary nickel based catalyst that has high activity and high temperature tolerance. Exothermic reaction heat is removed via heat exchange between stages to produce high pressure and superheated steam. High conversion to methane can be achieved in this multiple reactor approach. The process stream leaving the final reactor is cooled, dried and compressed to meet pipeline specifications for natural gas. Typical SNG product specifications are shown in Table 24.

- **Power Generation Block.** A portion of the clean synthesis gas from the acid-gas treatment step is diverted to a package boiler where it is burned in air. Heat is recovered from the high temperature flue gas exiting the boiler and is used to make steam for the steam turbines. The boiler is a multi-chamber, multi-pressure design with chamber pressures of typically 1,800 psia and 450 psia for the high pressure and intermediate pressure steam turbine sections, respectively. In addition to generating and superheating steam, the boiler reheats steam released from the high pressure steam turbine and provides condensate and feedwater heating and pre-heating.

  The steam turbine consists of a high pressure section (~1,800 psig, 1,050 F), an intermediate pressure section (~ 400 psig, 1,050 F), and a low pressure section. All three sections are connected mechanically to an electric power generator by a common shaft.

- **Balance of Plant (BOP) Units**
  Product transport:
  Facilities for compressing SNG and preparing it for transport offsite are provided.
  Water systems:

Systems are provided for cooling towers, to prepare boiler feed water (BFW), waste water treating, storm water handling, and fire water systems.

Electrical transformers and plant power distribution facilities are provided.

Instrumentation and Controls:

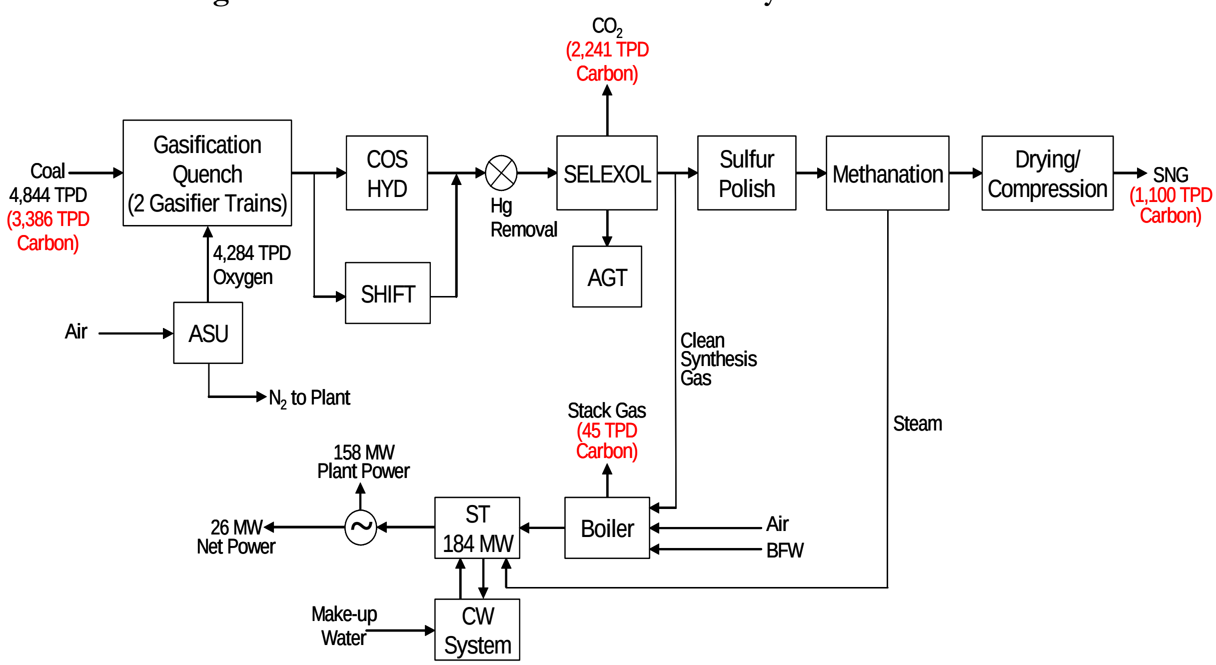
Unit operations instrumentation and control systems are provided.

Technical Description of SNG Cases Analyzed

- **CASE 1: SNG from Eastern Kentucky Coal, No Carbon Capture.** Figure 5 shows a block flow diagram for Case 1. This system produces about 74 million standard cubic feet per day of SNG. It uses Eastern Kentucky coal as feed material to two trains of single stage, slurry feed gasifiers.

  The as-fed coal input to the plant is 4,844 TPD. The products from this plant configuration are 71,081 million Btu's of SNG per day and 184 MW of gross power. The bulk of the power for the plant is provided by the superheated steam from the methanation reactors. Additional power is provided in a boiler by burning clean synthesis gas. The total plant parasitic power is estimated to be 158 MW therefore the net power available for sale is 26 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 60 percent.

Figure 5. Case 1 - SNG from East Kentucky Bituminous Coal

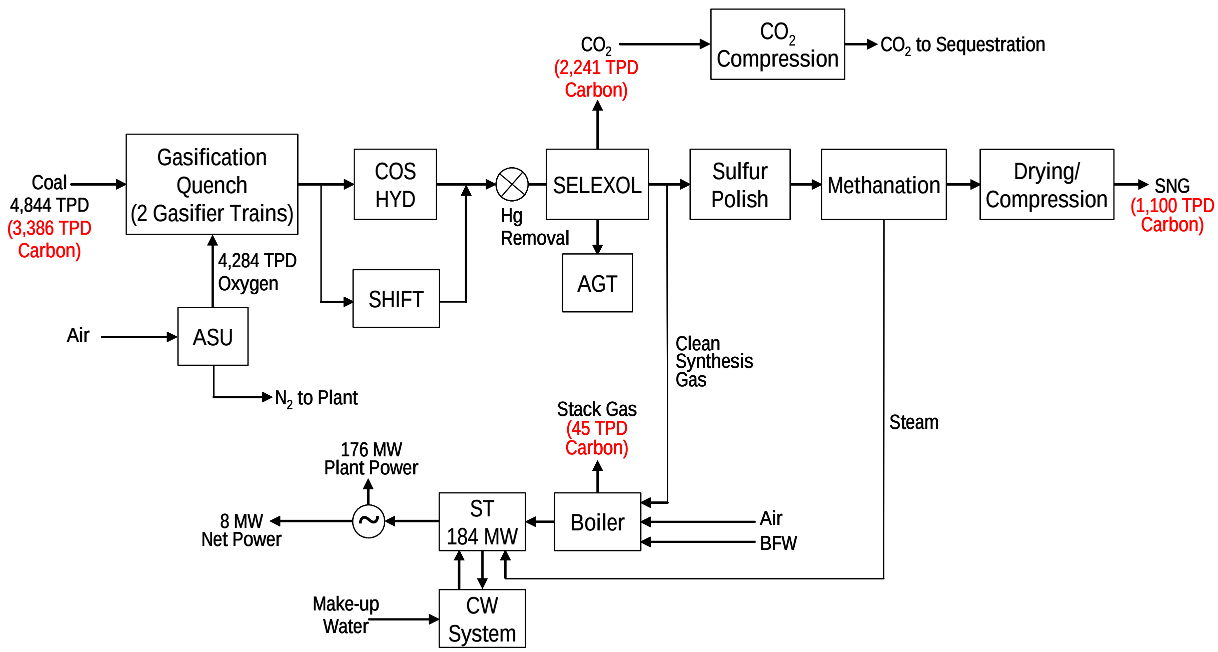


- **CASE 2: SNG from Eastern Kentucky Coal with Carbon Capture.** The process arrangement for this case is shown in Figure 6. In this case, the carbon dioxide from the Selexol unit is collected and compressed to 2,000 psi for subsequent sequestration. This system also produces about 74 million standard cubic feet per day of SNG. It uses Eastern Kentucky coal as feed material to two trains of single stage, slurry feed gasifiers.

The as-fed coal input to the plant is 4,844 TPD. The products from this plant configuration are 71,081 million Btu's of SNG per day and 184 MW of gross power. The total plant parasitic power is estimated to be 176 MW that includes the power for compression of the carbon dioxide; therefore, the net power available for sale is only 8 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 58.8 percent.

Referring to Figure 6 it can be seen that of the 3,386 TPD of carbon entering the plant with the coal, 1,100 TPD is contained in the SNG product. In the Selexol unit, about 2,240 TPD of carbon is removed while only 45 TPD of carbon is emitted from the boiler stack. This represents a carbon removal efficiency of greater than 98 percent.

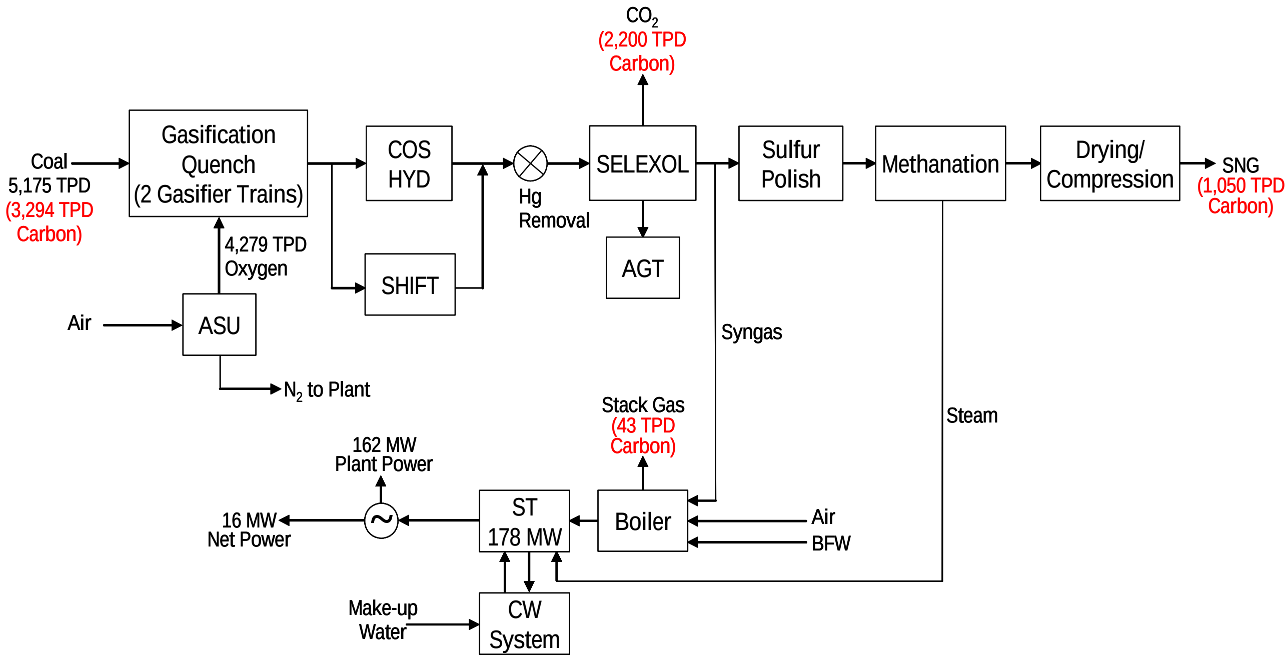
Figure 6. Case 2 - SNG from East Kentucky Bituminous Coal with CO_2 Capture



- **CASE 3: SNG from Western Kentucky Coal, No Carbon Capture.** Figure 7 shows a block flow diagram for Case 3. This system produces about 71 million standard cubic feet per day of SNG. It uses Western Kentucky coal as feed material to two trains of single stage, slurry feed gasifiers.

The as-fed coal input to the plant is 5,175 TPD. The products from this plant configuration are 67,605 million Btu's of SNG per day and 178 MW of gross power. The total plant parasitic power is estimated to be 162 MW therefore the net power available for sale is only 16 MW. The overall thermal efficiency of the plant on an HHV basis is calculated to be 57.5 percent.

Figure 7. Case 3 - SNG from West Kentucky Bituminous Coal



Economics of SNG Cases Analyzed

Table 16 summarizes the capital equipment costs for the three Kentucky coal cases analyzed in this study. For convenience the capital costs are disaggregated into major plant sections. Costs for many of the process units in these SNG plants were derived from a recent study commissioned by the National Energy Technology Laboratory. This study included an updated techno-economic analysis of Integrated Coal Gasification Combined Cycle (IGCC) plants of a similar size to the SNG plants analyzed in this study. IGCC plants contain many unit operations common to SNG including coal gasification, synthesis gas cleaning, air separation, and steam turbines. The costs of other units specific to SNG, including methanation reactors, were obtained from other sources.

Coal and sorbent handling refers to all equipment associated with the storage, reclaiming, conveying, crushing and sampling of coal. The gasification section includes the coal feeding, the gasifiers, quench system, and slag removal. The air separation unit (ASU) is a cryogenic system for separation of oxygen and nitrogen that can produce the 99.5 percent oxygen product needed for the production of SNG. The syngas cleanup system contains several components that remove hydrogen sulfide, carbonyl sulfide, cyanide, ammonia, particulates, mercury, and carbon dioxide. It also includes acid gas treatment, sulfur recovery, and water gas shift. The carbon dioxide capture section includes carbon dioxide removal and, in case 2, carbon dioxide compression to 2,000 psi. The methanation section includes the methanation reactors and SNG drying and compression. The power block includes a package boiler system, steam turbines, cooling water systems, feedwater and other plant water treatment systems, and the plant electrical and distribution system. The balance of plant includes instrumentation and controls, site improvements, and buildings and structures.

Referring to Table 16 the total installed costs of the Kentucky coal plants vary from $702 million (MM) for case 1 to $718 MM for case 2.

Table 16. Capital Equipment Costs (MM$) for SNG from Kentucky Coal

	Case 1	Case 2	Case 3
Plant Size	**74 MMscfd SNG**	**74 MMscfd SNG**	**71 MMscfd SNG**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Western KY Coal Without Carbon Capture**
Coal and Sorbent Handling	20	20	21
Coal and Sorbent Prep and Feed	34	34	36
Feedwater and Misc BOP Systems	26	26	26
Gasifier and Acc.	153	153	153
Air Separation and Compression	81	81	81
Syngas Cleaning and Shift	114	113	118
CO_2 Compression	0	17	0
Combustion Turbine and Acc.	0	0	0
Methanation	79	79	75
Boiler with ducts and Stack	38	38	38
Steam Turbine and Acc.	51	51	51
Cooling Water System	27	27	26
Ash/Spent Sorbent Handling	29	29	35
Accessory Electrical Plant	12	12	11
Instrumentation and Control	14	14	14
Site Improvements	12	12	12
Buildings and Structures	12	12	12
Total Capital Equipment	**702**	**718**	**709**

Table 17 summarizes the additional capital requirements for these plants. This includes home office costs (mostly front end engineering and design, i.e.: FEED, and detailed engineering design), process and project contingency, license, financing and legal fees, and non-depreciable capital. An overall project contingency of 5 percent has been applied to all of the cases to reflect the level of project definition for this non-site specific feasibility analysis. The total capital requirements varied with plant size from $897 MM in case 1 to $919 in case 2.

Table 17. Additional Capital Costs (MM$) for SNG from Kentucky Coal

	Case 1	Case 2	Case 3
Plant Size	**74 MMscfd SNG**	**74 MMscfd SNG**	**71 MMscfd SNG**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Western KY Coal Without Carbon Capture**
Home Office	60	61	60
Process Contingency	17	19	17
Project Contingency	39	40	39
License Fees	25	25	25
Financing/Legal	25	25	25
Non-depreciable Capital	30	30	30
Total Capital Equipment	702	718	709
Total Capital Requirement	**897**	**919**	**905**

Table 18 summarizes the annual operating costs for these Kentucky coal SNG plants. Fixed operating costs include royalties, labor and overhead, administrative labor, local taxes and insurance, and maintenance materials. Variable operating costs include coal, catalyst, water and chemicals, and other which are primarily solids disposal costs. The coal costs were assumed to be $35 per ton for the higher quality Eastern Kentucky coal and $30 per ton for the lower quality Western coal. The by product credit refers to sales of recovered sulfur. Net annual operating costs vary from $111 MM for case 2 to $102 MM for case 3. There are no purchases of electricity because all power required is generated on site.

Table 18. Annual Operating Costs (MM$) for SNG from Kentucky Coal

	Case 1	**Case 2**	**Case 3**
Plant Size	**74 MMscfd SNG**	**74 MMscfd SNG**	**71 MMscfd SNG**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Western KY Coal Without Carbon Capture**
Royalties	4	4	4
Coal feed	55.69	55.69	51
Catalysis/Chemicals	3	3	3
Labor/Overhead	18	18	16
Administrative	3	3	3
Local Taxes and Insurance	18	19	17
Maintenance and Materials	7	7	7
Other Operating Costs	2	2	2
Gross Annual Op Costs	110.7	111.7	103
Byproduct credit	1	1	1
Net Annual Op Costs	**109.7**	**110.7**	**102**

Table 19 summarizes the overall inputs of coal and outputs of SNG and electric power from the Kentucky coal plants. Also included on this table are the estimated plant parasitic power, gross power, sulfur recovered, estimated SOx and NOx emissions, and carbon dioxide released/captured. Coal feed varies from 4,844 TPD for the Eastern Kentucky coals in cases 1 and 2 to 5,175 TPD for the Western Kentucky coal, case 3. In case 2, where carbon is captured, only about 165 tons per day of CO2 are released to the atmosphere while 8,200 tons per day are captured and sequestered. In cases 1 and 3 where no carbon is captured, more than 8,200 tons per day of CO_2 are released to the atmosphere. The overall thermal inputs and outputs from the plants allow the overall efficiency to be determined. The overall system efficiencies varied from 57.5 to 60 percent with case 1 having the highest efficiency and case 3, with the Western Kentucky coal, the lowest.

Table 19. Inputs and Outputs for SNG from Kentucky Coal

	Case 1	Case 2	Case 3
Plant Size	**74 MMscfd SNG**	**74 MMscfd SNG**	**71 MMscfd SNG**
Configuration	**Eastern KY Coal Without Carbon Capture**	**Eastern KY Coal With Carbon Capture**	**Western KY Coal Without Carbon Capture**
Coal feed (TPD as received)	4,844	4,844	5,175
Net Power Sales (MWe)	26	8	16
Gross Power (MWe)	184	184	178
Parasitic Power (MWe)	158	176	162
Sulfur (TPD)	38	38	174
CO_2 captured (TPD) CO_2 released (TPD)	0 8,380	8,217 165	0 8,220
SOx (TPD)	0.0045	0.0045	0.0209
NOx (TPD) dry @ 15% O_2	0.0792	0.0792	0.0754
Coal HHV (MMBtu/D)	121,885	121,885	119,781
Products HHV (MMBtu/D)	73,211	71,736	68,916
Overall Efficiency (HHV)	60.1 %	58.9 %	57.5 %

Table 20 summarizes the economics for each of the three cases. The capital cost of these plants in terms of capital dollars per million Btu's produced per day (MMBtuD) varies from a low of $12,621/MMBtuD in case 1 to $13,391/MMBtuD in case 3. In case 1, the SNG required selling price (RSP) is estimated to be $9.10/MMBtu, $9.47/MMBtu for case 2, and $9.39/MMBtu for case 3. The RSP was calculated using a discounted cash flow analysis with the economic assumptions shown in Table 21. The sum of the operating costs and coal contributes about half of the RSP with the remainder being the capital cost. [For larger scale SNG plants, economies of scale bring down gas costs or RSP to $7.50 to $8.00 MBtu.]

Table 20. Economic Summary for SNG from Kentucky Coal

	Case 1	Case 2	Case 3
Coal Feed Type	Eastern KY	Eastern KY	Western KY
Configuration	No Carbon Capture	Carbon Capture	No Carbon Capture
Capital ($/MMBtu per day)	12,621	12,923	13,391
Capital ($MM/YR)	4.71	4.82	5.00
O&M ($MM/YR)	2.31	2.36	2.30
Coal ($MM/YR)	2.39	2.39	2.30
Power Credit ($MM/YR)	0.31	0.10	0.20
RSP SNG ($/MMBtu)	9.10	9.47	9.39

Table 21. Parameters and Assumptions Used in Economic Analysis

Economic Parameter / Assumption	Value
Construction Period	3 years
Incurred Capital Cost Construction Year 1	20%
Incurred Capital Cost Construction Year 2	50%
Incurred Capital Cost Construction Year 3	30%
1st Year Availability	45%
2nd Year Availability	81%
3rd Year and Beyond Availability	90%
Plant Lifetime	25 years
Return on Equity	15%
Depreciation Method	Double declining balance (16 years)
Debt: Equity Ratio	67:33
Interest Rate	8%
Inflation Rate	3%
Tax Rate	40%
Sulfur Price	$80 per ton
Bituminous Coal Price	$35 (EKY) and $30 (WKY) per ton

Water Use for SNG Cases

Table 22 summarizes the estimated water balance for case 1. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of syngas hydrogen in the boiler. The cooling water system (mechanical draft cooling towers) is by far the largest consumer of water, followed by the water lost in the boiler flue gas. The raw water flow of 2,639 gallons per minute represents the total amount of water to be supplied from local water resources to provide for the needs of the plant.

Table 22. Kentucky Coal SNG Facility Water Balance for Case 1

Water In Location	Flow (gpm)	Water Out Location	Flow (gpm)
Moisture in coal	47.4	Water lost in Gasification Shift	158.4
Combustion of H2 in the Boiler	33.8	Ash handling blowdown	86.4
Moisture in air to the ASU	13	Water with slag	49
Moisture in air to the Gas Turbine	34.2	Water lost in WGS reaction	364.5
Raw water	2,639	Boiler flue gas	11.2
		Sour water blowdown	62.4
		Cooling Tower drift	4.7
		Cooling Tower Evaporation	1,345
		Cooling Tower Blowdown	672.4
		Moisture in ASU vent	13
Total	**2,767**		**2,767**

Summary and Conclusions for SNG Cases

For the techno-economic assumptions and basis used in this study, the results summarized in Table 23 support the following conclusions:

- This feasibility study has estimated that substitute natural gas (SNG) can be produced from Eastern and Western Kentucky coals using existing technologies for between about $9 and $9.40 per million Btu's. [For larger scale SNG plants, economies of scale bring down gas costs or RSP to $7.50 to $8.00 MBtu.] The price of natural gas has been very volatile and varies considerably and is particularly influenced by winter temperatures and electric power demand. Currently the Henry Hub price is around $7 per MMBtu but this will rise if the winter becomes cold. [In the winter of 2005 – 2006, the price spiked to about $14.00/mcf]. .

- For the economic assumptions and coal types used in this study, the most economically attractive configuration is to use an Eastern Kentucky coal with no carbon capture. According to the coal analyses, Eastern Kentucky coal is of higher quality than the Western Kentucky coal. It has a higher heating value, greater carbon content, and lower sulfur and chlorine levels.

- Annualized capital costs and operating costs (including coal cost) contribute approximately equally to the required selling price of the product.

- When carbon capture is required there is a small efficiency penalty of about 2 percent and a cost of product penalty of about 4 percent. The efficiency penalty is small because even in the cases where carbon capture is not required, the carbon dioxide still has to be removed. The only difference is that the carbon dioxide has to be compressed to 2,000 psi when capturing is necessary. This additional cost does not include the actual cost of sequestering this compressed carbon dioxide. Ideally this carbon dioxide could be used for enhanced oil recovery if there are suitable opportunities within a feasible distance from the plant.

- The water use requirements of the Kentucky SNG plants are at or below typical utility averages. If water availability is an issue the SNG plant could be redesigned for minimal water use by maximizing the use of air cooling.

- It should be cautioned that this study is not a detailed engineering and economic analysis. It is a feasibility analysis using certain specified coal inputs to generic non site specific conceptual SNG plants. The technical performance of the plants is modeled in sufficient detail to have a high level of confidence in the overall product output, coal input, power and utilities consumption and hence overall efficiency. Because this analysis is at the feasibility level and non site specific, the accuracy of the construction cost estimates is expected to be about +/- 30 percent. However, although there is some uncertainty in the absolute costs, the cost differences between the cases are considered to be meaningful.

Table 23. Summary Results for SNG Cases

Case Number - Configuration	SNG Production (MMscfd)	Exported Power (MW)	Capital Required ($/MMBtu)	SNG RSP ($/MMBtu)	Efficiency (% HHV)
1 – Eastern KY Coal without Carbon Capture	74	26	12,621	9.10	60.1
2 – Eastern KY Coal with Carbon Capture	74	8	12,923	9.47	58.9
3 – Western KY Coal without Carbon Capture	71	16	13,391	9.39	57.5

Table 24. SNG Product Specifications

SNG Constituents	Concentration (Mole %)
CH_4	94 – 96
CO_2	0.5 – 1
H_2	0.5 – 1
CO	Nil
N_2 + Ar	2 – 3
HHV (Btu/scf)	950 – 975

(Page left blank intentionally.)

Chapter 4: Needs for Research, Development and Demonstration

This section addresses:
1. Hurdles associated with pioneering energy technologies (financial, construction, technical and early operational risks).
2. Value/benefit of improvements, know-how, show-how, experience and moving along the learning curve in reducing risk/improving investor confidence/lowering the "hurdle rate" for deployment.
3. Specific unmet technology needs for further research and development (readiness, state-of-the-art of the technology, acceptability of the fuels).
4. Needs for labor force development and training.

I. Concerns about Risk and Return

CTL technologies offer the prospect of supplanting petroleum – of producing clean fuels and chemicals from an abundant domestic resource, but their commercial deployment is constrained by certain economic and technical barriers. First, we've explained that deployment is constrained by substitution forces: coal will be a viable substitute to petroleum when the selling price for coal-derived fuels is comparable to the cost of producing them from oil, in the absence of factors outside the marketplace that could speed deployment.

In addition, the deployment of pioneering energy technologies brings with it certain financial and technical risk not normally associated with proven technologies. These include a greater capital risk associated with financing and constructing large projects, early siting risks and construction delays, and operating risk associated with the early operational performance of the plant. Absent performance guarantees or the taking of an equity position by the technology vendor and/or engineering, procurement and construction (EPC) company (so-called "wraps"), investors expect to be compensated for taking these added risks. Thus, the project hurdle rate for pioneering technologies is inevitably higher than that required for proven or mature technologies – especially for these exceptionally large and capital intensive projects.

In other words, on a crude oil equivalent basis, the cost of producing coal liquids may need to be well below the prevailing price of petroleum or conversely the rate of return will need to be high to induce private investment in $4+ billion in plant and equipment. Moreover, the rate of return will need to compensate for the uncertainty (risk) associated with predicting future crude oil prices, and early technical performance.

Specific hurdles associated with CTL and SNG technologies follow.

Financial Risk

- A major and dominant barrier in the US is the apparent lack of serious "owner-operator" players. Since a meaningful FT facility would have a capacity of at least 40,000bbl/d, and preferably larger, that implies an investment of the order of $2.4 billion. This is not something which can be handled by a company with a weak balance sheet. Putting a credible team together to share risk but in which members also are familiar with the technology (part utility, part refining, and part petrochemical) is an essential element.

Facility Siting and Construction Risk

- Construction: US companies have the wherewithal to build such facilities. This has been demonstrated adequately. The crunch will come if many need to be erected simultaneously. Skilled artisan labor/technicians might be a limiting factor. The manufacturing and heavy equipment suppliers might be in a similar situation – as is happening in several countries where CTL projects are under way.

- Environmental issues are often seen as major hurdles. In practice, technologies exist to take care of such concerns but there are opportunities to improve the economics of the environmental facilities. The extent of CO_2 emissions is one which has drawn criticism due to the nature of the chemistry of gasification and FT synthesis. However, in a carbon constrained world, FT plants benefit from the source of CO_2 (typically from a Rectisol plant) as being CO_2 rich (typically above 95%) and suitable for compression and sequestration.

Operating Risk

- Operational risk: This is primarily a function of skilled labor. This aspect needs to be addressed at both the chemical/process engineering and the operator level.

- Although the chemistry is "old", there is continuing improvement in any technology as it gets applied. Examples are the progress made in Lurgi gasification at Sasol and Great Plains over a few decades and the completely new reactor designs that Sasol came up with after more than 20 years of operation. Identifying such opportunities for incremental progress is hard for non-insiders and the companies in the business keep this close to their chests. FT catalysis seems an attractive area of R&D and there are certainly opportunities for improvement. There are however few areas of catalysis so well researched (and patented) and in the overall application of the technology the actual performance of the FT catalyst is a relatively minor financial component. Greater advantages are potentially available in systems integration, including energy optimization and infrastructure rationalization.

- The level of expertise in the US in the area of the total CTL/CTG complex differs for the various process steps. For infrastructure units - power generation, air separation (oxygen) and such units - the expertise is well established. It is not the case in gasification, with the notable exceptions of operating experience at the Great Plains Lurgi gasifiers and the Eastman Texaco (now GE) gasifiers. In the FT reactor plant, there is limited expertise available from Syntroleum and Rentech, at different levels of capacity, but below real demonstration scale. Exxon ran a 200 bbl/d FT unit for a number of years, but it is not currently involved in any US commercialization. Shell is participating in the WMPI project in Pennsylvania, but not in the FT section, which will be Sasol technology at the scale of only 5,000 bbl/d.

Product Risk

- The fuels have been demonstrated to be compatible with commercial vehicles (in South Africa a user doesn't know whether the fuel is from a CTL facility, a refinery or a blend). Corrections to specifications (lubricity and the like) are made before the products leave the site. There is room for optimization between product requirements and primary and secondary processing. Logistically, the products are transported in usual commercial systems. When premium values should be obtained (superior to crude derived materials), separate distribution channels could be justified.

II. Unmet Technology Needs

As indicated above, the prospect of CTL technologies is alluring, but the deployment of pioneering energy technologies bring with them certain financial, construction, operating and technical risk not normally associated with proven technologies. Risk can be reduced and deployment stimulated by a variety of means, including price supports, product take-off agreements, tax breaks, and financing incentives for early adopters. It can also be reduced by making "learning investments" for research, development and demonstration (RD+D) to reduce the technical hurdles of new energy technologies. It is an accepted premise that with successive deployments of a pioneering technology there comes with it learning and improved operational experience. Described as the learning curve, learning-by-doing (for producers) and learning-by-using (for product users), the assumption is that experience leads to reductions in cost or improvements in operating efficiencies. There are a number of technical issues which, if addressed in creative ways, can alleviate some of the risks associated with the adoption of CTL technology.

Gasification Section

- The gasification of coal has been evaluated and practiced for many years. There are separate development activities under way to address identified needs in the area of gasification. DOE is actively funding some of the work and industry is also working towards improving the performance, reliability and cost effectiveness of various gasifier types. Some of this work is done in conjunction with the increased commercialization of Integrated Gasification Combined Cycle (IGCC) units for power generation.

Gas Cleanup/Conditioning

- Syngas cleaning is an area where there are further opportunities for improvement. This also involves cost reduction and the adjustment of the H2 to CO ratio in the syngas for optimal FT performance.

Gas Conversion by FT Synthesis

- Although the cobalt catalysts (mostly proprietary) have expected lives of up to 5 years, there might be cheaper catalyst formulations with similar life expectancies. For iron catalysts, which are cheaper, the thrust for longer life and cheaper production costs, would also apply.

- The robustness (mechanical attrition resistance) of catalysts varies a great deal and especially some iron catalysts could be relatively weak, limiting the separation of catalyst and wax. Although this problem has been resolved by Sasol, there is little open access information on these issues, and open R&D will reduce the concern in this area.

- In the FT synthesis, there is great variation possible to fine tune selectivities (such as olefin/paraffin ratios, degree of branching, chain length, level of oxygenates and type of oxygenates and the like). The product spectrum is influenced by a large number of parameters like catalyst characteristics, (reduction/pretreatment, morphology, promoters, mechanical strength etc.), process variables (temperature, temperature gradient, pressure, syngas flow rate, syngas composition, gas purity etc.) as well as reactor design features. The combination of these process conditions determines the conversion and the selectivity pattern for the chosen system. There are no an open R&D facilities where such work can be done at a scale beyond the normal scientific lab scale. Having such a facility or facilities could provide potential project developers with a platform from which to optimize the process for their market needs by integrating the synthesis optimization with the product optimization.

Product Work-up or Refining

- The discussion here is restricted to the "Low Temperature" FT or slurry bed systems since these are the simplest FT plants that are likely to be built first in the US. The primary products from the FT reactor are typically separated by a series of thermal steps to separate products in boiling point fractions analogous to a conventional refinery. The lighter gases can, depending on the level of syngas conversion and the value of the energy in the tail gas, be partially cleaned up for recycle (e.g. water removal) or it can be used as a fuel gas in the plant. In some cases (especially when using a Lurgi gasifier), the methane in the gas can be separated out and reformed to produce more syngas.

- Without running through all the cuts which can possibly be recovered and purified, it can be stated that the simplest configuration is likely to be that the light liquids ("naphtha") can be used either as a petrochemical feedstock or potentially as a gasoline component after significant octane number enhancement through isomerization/alkylation (here research could be applied to improve yields). The next heavier cut would be the "straight run" diesel/fuel oil cut and lastly there will be heavier waxes which can be hydro-cracked to bring the boiling point into the diesel range. Variations would be used to produce different grades of jet fuel. Depending on specifications, hydro-isomerization would also be used to improve the cold temperature properties and lubricity characteristics.

- In the area of product characteristics, there are likely to be opportunities for analytical method development for simpler and more applicable testing procedures, and collaboration with certification authorities will be desirable.

- As in a refinery there are usually "polishing" steps and special fractionation and or hydro-treating steps to ensure that all specifications for a particular product grade will be met. Thus special grades of fuels and chemicals can be produced in an FT facility, such as special grades of jet and aviation fuels or other "boutique" fuels and chemical components. This is clearly an area for product specific R&D based on the FT system and by combining the FT system parameters with a multi-purpose continuous product work-up facility, a very powerful tool for companies interested in making particular products, can be established.

- The issue of separating and purifying components and fractions from complex streams in an FT facility is part of the challenge to maximize profits. In this area creative and novel separation technologies could be developed to add value to a CTL venture.

Fuel Quality Testing, Performance and Acceptability

- Systematic research on the application of FT fuel in gas turbine and diesel engines is required before FT fuel can become a widely accepted commercial transportation fuel. Thermal and storage stability, cold flow properties, atomization performance, fuel/air mixing, combustion stability, emission performance, compatibility with coatings and elastomers, and lubricity are research topics of significant importance and interest to industry, DOD, and government agencies such as the FAA.

- With respect to thermal and storage stability, future Air Force needs call for hypersonic aircraft that will require extensive use of the fuel as a coolant. Endothermic hydrocarbon fuel is a key enabler for hypersonic vehicles by absorbing heat as they are cracked to lower molecular weight compounds. The chemical structure of the fuel determines the possible endotherm (chemical cooling capacity) and the exact products of the endothermic reaction. The main problem to date with endothermic fuels has been fouling of the catalyst in the heat exchanger/reactor due to coke formation. By optimizing the fuel structure, high endotherms and non-coking endothermic products could be realized.

- Utilization of FT fuel with lean premixed combustion (LPC) techniques is important in both diesel engine and gas turbine applications. LPC intrinsically suppresses NO_x formation during the combustion process, because the high temperature zones caused by nearly stoichiometric combustion are avoided. LPC has been successfully applied in stationary gas turbines and manufacturers are pursuing LPC applications in aviation gas turbines and diesel engines. Combustion stability is one of the major concerns in LPC. Flashback and pressure oscillations need to be eliminated. Better atomization, mixing, ignition, and combustion control are extremely required.

- Diesel engines are the main power source for heavy-duty applications such as trucks and buses. They are attractive because their higher compression ratio and direct injection of fuel result in greater efficiency than that of typical spark-ignited engines. But, they are a source of pollutants, primarily in the form of particulate matter (PM) and nitric oxides (NO_x). The Environmental Protection Agency (EPA) has imposed strict limits, which come into effect in the 2007-2010 time frame, on these pollutants. Premixed charge compression ignition (PCCI) or homogeneous charge compression ignition (HCCI) is a promising LPC approach to reduce NO_x emission. Based on current understanding, however, lower cetane number is required for LPC. A better understanding of this issue could be very important for the application of FT fuels in the future.

- For diesel engines to meet strict EPA limits, it is also necessary to employ exhaust after-treatment devices, e.g. NO_x traps and particulate filters. This is expensive and may lower the efficiency of the engine. Optimum design of these after-treatment devices is important to reduce cost and the adverse effects on engine efficiency. FT fuels derived from coal are an attractive alternative in several ways to conventional diesel fuel. They have a higher cetane number than the diesel fuel. This leads to shorter ignition delay and enables retarded injection, both of which would lower the NO emissions. Furthermore, the absence of aromatic components in the fuel reduces the tendency to form particulate matter. FT fuels also have negligible sulfur content which further reduces the particulate emissions. The absence of sulfur is also a significant advantage in the design of exhaust after-treatment devices. The introduction of a zero sulfur fuel would have a positive impact on pollution, including NO_x reduction because of lack of poisoning the catalyst. It would have an effect on all of the after-treatment strategies in diesel engines, because of open of the potential catalysts. In addition, the use of a zero sulfur fuel offers benefits to the EGR systems of diesel engines due to an elimination of corrosion.

Environmental Considerations

- As is well known, coal is a complex material and processing it into high purity clean liquid fuels require detailed attention to environmental, health and safety issues. In a generic sense it can be stated that technologies are available to address the issues regarding the various emissions, effluents and solids residual materials. The question is to what extent the costs associated with these processing steps will impact the overall viability of a venture. For example, the Secunda facilities, as erected in the late 1970's/early 1980's at a cost of ~$6billion included capital of about $900 million (15%) to handle aspects related to the environment. Subsequently continuing investments were made to improve environmental performance. Thus, CTL facilities can be clean coal facilities and as is the case with most of the other process units, there are opportunities to enhance the viability by bringing down costs by improving performance.

- Specific research topics could include the efficient use and re-use of water (the Secunda facility is a zero effluent discharge plant with the exception of regulated boiler blow-down); beneficial use of the ash from the gasifiers (this will depend on the type of gasifier selected); further improvements of technologies to capture sulfur from the gasifiers as well as from the power plant; improved mercury capture(depending on gas purification process); control of volatile organic components and last but not least optimization regarding potential CO_2 capture from all CO_2 sources in a CTL facility.

Systems Analysis and Integration

- To support the above activities it will be essential to have a systems analysis and integration capability. This can be applied for the work plan itself and also to analyze the components in the process facility. These skills will have to be developed and models will have to be verified against the experimental results to enable initial assessments of scale-up opportunities. The software capabilities to control the integrated R&D facility and to apply process engineering optimization to the operation of the facility and to conceptual process configurations will be an ongoing activity.

- At a more fundamental level the capability of computational chemistry could be used to assess ways to improve separations and catalysis in various parts of the plant.

Scale-up and Demonstration

- The reactor types used commercially (up to 20,000 bbl/d per single reactor) have been fine tuned over a long time and incremental improvements are made continually. Some key factors in reactor design include the hydrodynamics (gas and catalyst dispersion, back mixing, temperature profiles, heat distribution), the withdrawal of the high amount of exothermic heat from the FT reactor, good feed gas distribution (mostly patented technologies), the optimization of recycle streams, the effective recovery of catalyst particles (in fluidized beds in the gas phase and in slurry rectors from the wax), pressure drop (especially for tubular reactors as used by Shell) and catalyst feed and withdrawal systems as might be applicable. Many of these aspects are practical engineering design optimization best done by engineering design specialists rather than by researchers.

- Developing and verifying reactor design models become meaningful at reactor diameters above about 2 feet, so that this activity will only be valuable at the larger scale of operation before full commercialization. The products produced in smaller units will nevertheless be typical of FT products. If collaboration with engineering contractors can be established, that could strengthen a RD&D team to focus the R&D on relevant issues which will have an economic impact. Normally design details are protected very well by the technology owners. In a similar way, the expertise for scale-up resides mostly with experienced contractors.

III. Labor Force Development and Training

Efforts need to be made to build up human capital – the future generation of skilled energy technologists, engineers and operating personnel – that will be needed to sustain a CTL and SNG industry. Due to the cyclical interest in CTL, the scientific and engineering capabilities which were devoted to energy programs of the 1980's and 90's have dissipated. A new generation of technologists needs to be nurtured. One of the best ways of creating this skills base is to stimulate and fund RD+D at appropriate institutions which have the facilities to teach and train students in the practical applications of science and engineering. The relevance of training can thus be assured while the stimulus of a creative environment will lead to further technological innovations.

Estimates of Construction and Operating Labor

Construction labor requirements were estimated by comparing the labor requirements per $1 million in capital costs for similar Kentucky projects, as well as from estimates reported by other sources. These estimates were later confirmed as reasonable in consultation with industry experts, including an experienced EPC contractor.

Construction labor requirements for Kentucky-specific projects that were evaluated included an integrated gasification combined (IGCC) cycle power plant and a circulating fluid bed combustion (CFB) power plant. The IGCC power plant was proposed to be built for construction costs of $502 million in 2006 dollars; the CFB power plant for $542 million. Both plants were proposed for the same site. The construction labor estimate for the IGCC power plant was 1000 people during peak construction; 800 workers for construction of the CFB. These employment levels yield ratios of 1.5 - 2 workers per $1 million of investment. Other published estimates have put the range from as low as 0.7 to 1 worker per $1 million of investment. Applying a conservative range of .7 to 1.25 workers per $1 million of investment and a 0.66 exponential scaling factor result in the estimates given in Table 25 for plants of varying size and cost.

Operating labor was estimated based on what is reported in the literature about the operations of similar facilities that exist or are planned. These estimates were also scaled by a .66 exponential scaling factor for the larger plants. The estimates for operating personnel also appear in Table 25.

Table 25. Estimates of Construction and Operating Labor

Size/Capacity Bbl/day	Investment Billions $	Peak Construction Labor	Operating Labor *
10,000	0.91 @ $91K/daily bbl	650 – 1,100	180 - 200
30,000	2.3 @ $77K/daily bbl	1,350 – 2,300	375 - 400
60,000	4.4 @ $72.5K/daily bbl	2,150 – 3,650	590 - 630
100,000	7.0 @ $70K/daily bbl	3,000 –5,100	830 - 880

***Operating labor requirements highly dependent on plant design and configuration**

With respect to the mix of construction-related occupations, it is estimated that approximately ten percent will be professionally-trained engineering and managerial staff with the remainder taken from the skilled crafts. For the operating staff, it is estimated that 10 – 15 percent will be professional staff, 60 percent skilled operators and the remaining as administrative, security and maintenance staff. A sampling of occupations included in these classifications follows in Table 26.

Table 26. Sampling of Occupations Employed in CTL and SNG Plants

Engineering and Scientific	Construction Trades and Skilled Crafts	Plant Operators	Maintenance
Construction Engineers Petroleum Engineers Chemical Engineers Mechanical Engineers Electrical Engineers Environmental, Health and Safety Engineers Control System Engineers Industrial Chemists Analytical Chemists	Construction Equipment Operators Brickmasons, Blockmasons, and Stonemasons Cement Masons and Concrete Finishers Structural and Reinforcing Iron and Metal Workers Pipelayers, Plumbers, Pipefitters, and Steamfitters; Electricians and Electronics Technicians Carpenters and Millwrights Sheet Metal Workers Insulation Workers HVAC and Refrigeration Mechanics and Installers Drywall and Ceiling Tile Installers Plasterers, Pavers and Stucco Masons Painters, Paperhangers and Glaziers Roofers Carpet, Floor, and Tile Installers and Finishers	Gas Plant, Compression and Pumping Operators Petroleum Pump System Operators, Refinery Operators, and Gaugers Stationary Engineers, Fireman and Boiler Operators and Tenders Power Plant Operators Separating, Filtering and Precipitating Operators, and Tenders Conveyor Operators and Tenders	Industrial Machinery Mechanics and Maintenance Workers Diesel Service Technicians and Mechanics Heating, Air-conditioning, and Refrigeration Mechanics Heavy Vehicle and Mobile Equipment Service Technicians and Mechanics Machinists, Maintenance and Repair Workers

(Page left blank intentionally.)

Chapter 5: Role of Industry and Government in CTL and SNG

This section addresses:

1. The sort of "owner-operators", equity interest and "wrap-arounds" that exist now or are needed to provide performance guarantees and other assurances to reduce financial, technical and operational risk associated with CTL and SNG facilities.
2. A screening of candidate technologies for gasification and Fischer-Tropsch, including an identification of technology vendors, the readiness of the technology
3. The corporations, joint ventures, and other consortia that exist to finance, construct and operate CTL and SNG facilities (technology providers, operating companies, engineering procurement and construction companies).
4. The role of government at the federal, state and local level in stimulating deployment and commercialization.

I. Teaming Considerations

A commercial scale CTL or SNG plant will be, as indicated before, comprised of a number of individual process steps which all need to be operating in harmony to ensure profitability. It is therefore critical that adequate consideration be given to the selection of technologies and technology vendors. In a report such as this one, one supplier cannot be recommended to the detriment of another and therefore considerations are presented rather than recommendations.

The chosen suppliers of technology should provide the needed warranties that their plants will perform as agreed, but warranties should also be obtained for the overall configuration. Such overall "wrap-around" warranties are hard to obtain since few such plants have yet been erected in the USA. The best alternative is to select a reputable engineering, procurement and construction company (EPC) with related experience and in-depth understanding of the technologies to be incorporated in the plants. These considerations extend to, besides the main gasification, SNG and FT sections, other parts of the plant, including gas cleaning, solid and effluent treatment/disposal, permitting, and logistics regarding feed and products transportation.

Since SNG plants are not in operation in the US, other than the aforementioned Great Plains Gasification Plant in North Dakota, there are not other "role model" plants on other types of coal. However, in the case of SNG the methanation step of converting syngas to substitute natural gas, is not unknown and with a reputable engineering and construction team, such plants can be erected with a high probability of technical success. A more significant uncertainty is the overall economics and the financial parameters under which such a facility will operate.

II. A Screening of Candidate Gasification and Fischer-Tropsch Technologies

Gasifier Types and Vendors

Gasifiers can be classified as slagging or non-slagging, depending on the temperature of operation. If the operating temperature is above the melting point of the ash in the coal, it is called slagging. The high temperatures lead to the destruction of volatile heavier components from the coal, leading to a synthesis gas with predominantly hydrogen and carbon monoxide. Slagging gasifiers usually use fine coal in either a slurry with water or as pulverized feed. The fine material is entrained in the gasifier and due to the high temperatures, the reactions are very fast. The down-side is that the construction materials of the gasifiers need to be protected with either refractory bricks or with water jackets. These lead to higher maintenance costs and down-time when re-bricking of the refractory is needed.

The slagging gasifiers are primarily the GE (previously Texaco), the Shell and the E-Gas (ConocoPhillips) types. In the USA there are operating commercial gasification units in operation at Great Plains, North Dakota (Lurgi for SNG), Tampa Florida (GE for IGCC), Eastman Chemicals, Tennessee (GE/Texaco for methanol and chemical derivatives from methanol) and at Wabash, Indiana (E-Gas for IGCC). Several new projects are in the planning stage, most for IGCC but some for liquid fuels.

The non-slagging gasifiers fall into two categories: the "moving bed" or "fluidized bed units". In the case of the former, coal of at least ¼" size is required and the coal is fed to the top of the gasifier while steam and oxygen is introduced from the bottom such that the produced gases exit at the top. In this way good carbon utilization is achieved and the overall temperature stays below the melting point of the ash. Due to the lower temperatures, some of the devolatilized products from the coal are carried out of the gasifier with the syngas. These can be separated and used as such or recycled. The fluidized bed gasifiers use pulverized coal feed and the air or oxygen and steam are used to fluidize the fine coal. The carbon is not fully converted since some of it remains on the ash and usually a recirculation system or a separate combustion system is used. The Lurgi gasifier is the basic model for the moving bed gasifier. In practice the Lurgi gasifier is the type producing the largest amount of syngas on a world-wide basis.

A gasification process which is different from the above types is based on old technology to produce hydrogen by reacting coal with molten iron. It is under development by EnviRes, a Lexington, Kentucky-based company. A cyclical process called HyMelt® is used which produces hydrogen in one cycle and then carbon monoxide in another cycle. The process concepts were verified with DOE support at a test facility in Sweden and the project is under further development towards demonstration. The economics of this approach have not been published.

Currently the progress in gasification is increasing in momentum as a number of IGCC facilities have been announced and projects are under development. This implies that commercial experience in gasification will soon be at a much more mature level in the USA than up to the present. The main types of gasifiers were discussed previously and suffice it to state here that for a particular project the conditions regarding coal type and availability and the economics of the project as well as a number of related issues will be considered by the project developers to choose the most suitable gasifier for their application. For Kentucky coals the ash content is specifically to be considered as is the swelling characteristics of some eastern coals. The sulfur content, which plays a large role for power generation is not so critical for gasification since the sulfur is removed practically quantitatively for most syngas uses. Once the capital investment is made to install deep sulfur cleaning, the absolute quantity of sulfur in the feed coal is not a very significant factor any more.

The Table 27 below provides a summary of gasifier types, vendors and the state of maturation of available gasification technologies.

Table 27. Summary of Gasifier Types and Vendors

Gasifier Type and Vendor	Year Demonstrated	Year Commercialized	Proven for Power Generation	Proven for Chemicals	No. of Commercial References
Moving Bed					
Lurgi	1931	1936	Yes	Yes	Large no.
BGL	As above.	1958	Small Scale	Yes	Two (2)
Fluid Bed					
ABB PFBC	1980s	1985	Yes	No	<5
HTW	1956	1960s	Yes	Yes	<5
KRW	1998	Dormant since 2001	Yes	No	One (1)
KBR	1996-05	Demo only	Yes	No	None
U-Gas	1980s	1980s	No	Yes	Large no.
Entrained Flow					
GE (Texaco)	1940s	1950	Yes	Yes	Large no.
Conoco-Phillips	1978	1996	Yes	No	Two (2)
Future Energy	1975	1980s	Yes	Yes	2-3
Koppers-Totzek	1950s	1950s	No	Ammonia only	Large no.
Shell SCGP	1978	1993	Yes	Yes	Three (3)
Special					
Alchemix	Test rig 2003	Small scale 2005	No	No	None
EnviRes HyMelt®		Demo only	No	No	None

Source: Adapted from Rentech

Fischer-Tropsch Reactors and Vendors

The conventional FT reactors were tubes into which the catalyst was packed, usually as extrudates. Multiple tubes were fitted into a single shell with water surrounding them so that steam can be raised to withdraw the exothermic heat from the system. These reactors are referred to as fixed bed reactors. For the high temperature system another approach is applied, namely to use fine catalyst and entrain it into a fluidized bed which contain coils to remove the reaction heat. The catalyst can be circulated (circulating fluidized bed) or can be contained in a single vessel with the catalyst separated in the reactor from the products using cyclones. The large Sasol facility uses this type of reactor which can produce 20,000 bbl/day in a single reactor. Another version of this concept is now also applied to low temperature FT. In this case the reactor is filled with molten wax (the reaction product) and the gas is bubbled through the reactor which again contains equipment to remove heat. This configuration is called a slurry bed reactor or a bubbling bed reactor. The world's largest slurry bed reactor just came into production at the Oryx plant (Sasol/Qatar) and produces 17,000 bbl/d low temperature products per reactor per day. The Shell facility in Malaysia is using a fixed bed reactor with an undisclosed number of tubes (in the thousands). Other FT technology companies use either slurry reactors or fixed bed systems.

The choice of FT vendors is rather narrow. A number of project announcements have been made and every month new announcements appear in the press, but so far no FT facility has been run commercially in the USA. Many of the announced plants never reach the so-called the FEED (front end engineering and design) stage due to financing difficulties. These are often based on the risk due to the unproven track record of technology suppliers and also due to the fact that small CTL plants suffer from a "dis-economy" of scale. Some of the smaller FT companies are promoting technology packages but with little operational experience and thus investors are reluctant to take scale-up risks with unproven technology.

Sasol is capable of providing technology and expertise to make a success of a CTL venture in the USA. However as a company whose business has been traditionally to focus on production and not on licensing its technology and since Sasol prefers to take an equity stake in plants which apply its technology, it is not clear why Sasol would get involved in a US venture, given their resource constraints and the fact that they are at the time of writing involved in the final commissioning of the Qatar facility, which is likely to be expanded. Sasol also made it known that it is involved in evaluating other ventures in Australia and India, besides the two facilities in China and one in Nigeria. A recent development is the evaluation of a fourth Sasol facility in South Africa. With Sasol heavily committed there are not short-term prospects of a Sasol plant in the USA. Therefore, with Sasol an uncertainty, the technology hurdle for application of CTL in the USA seems at this time to be a significant one.

The Table 28 below is a summary of Fischer-Tropsch Reactor types, vendors and the state of maturation of available FT technologies.

Table 28. Summary of Fischer-Tropsch Reactor Types and Vendors

FT Reactor Type and Vendor	Year Demonstrated	Year Commercialized	No. of Commercial References
Fixed Bed			
Early German Models	1925	1937	Large no.
SASOL	1950	1954	Large no.
Shell	1970s	~1992	Several
BP	-	Demo only	None
Fixed Fluid Bed			
HRI	1940s	1952	Limited no.
SASOL	1980s	1989	Several
Circulating Fluid Bed			
SASOL	1940s	1954	Large no.
Slurry Bubble Column			
Ruhrchemie	1940s	-	Large no.
SASOL	1980s	1991	Large no.
Conoco-Phillips	-	Demo only	None
ExxonMobil	-	Demo only	None
ENI/IFP	-	Demo only	None
Rentech	-	Demo only	None
Statoil/PetroSA	-	Demo only	None
Syntroleum	-	Demo only	None

III. Corporations, Consortia and Joint Ventures in CTL and SNG Projects

Coal-to-Liquids (CTL) Projects

- **States.** Several states have expressed an interest in FT/CTL. These include Montana, Pennsylvania, West Virginia, Wyoming, Kentucky and others. In many cases incentives of different kinds were offered to encourage entrepreneurs and investors to locate their planned facilities in those states.

- **Headwaters.** Headwaters who took over the HTI technology have entered into agreements for CTL developments in the Philippines.

- **PetroSA.** PetroSA were previously known as Mossgas, located at the south point of Africa, using natural gas. It is a government owned facility. They licensed Sasol technology for their CTL and have recently joined forces with Statoil of Norway and erected a 1,000 bbl/d test unit using slurry bed technology. Results have not yet been published.

- **Rentech.**
  - Rentech prepared a presentation on their proposed project in Wyoming (accessible from the Rentech web site). This is a useful description of the considerations for a choice of gasification technology as well as a framework for economic analysis at an early stage to assess project feasibility.
  - Other projects include
    - With DKRW and Arch Coal: a project development agreement for a 10,000 bbl/d CTL plat in Wyoming.
    - A project for 1,900 bbl/day by 2009 at the E Dubuque Ill fertilizer facility and increasing it to 6,800 bbl/d by 2011. This will be based on ConocoPhillips gasification technology and will co-produce fertilizers and FT fuels.
    - A Wyoming project at Medicine Bow 11,000 bbl/d. This plant will use GE gasification technology.
    - Projects with Peabody in the Mid-West and in MT (Jul 06) for 10,000-30,000 bbl/d using 2 to 3 million t/ y of coal for the first plant and 6 to 9 million t/y for the larger one.
    - A Rentech subsidiary, Rentech Energy Midwest Co, is working with Kiewit Energy Company (KEC), Houston, Texas. Worley Parsons, under contract to KEC, will lead the Front End Engineering and Design (FEED).

- **Sasol.**
  - Sasol and Chevron have an alliance whereby Sasol provides the FT part and Chevron provides product work-up.
  - Sasol has an arrangement with Engelhard (Now BASF) to produce the Sasol proprietary cobalt FT catalyst. These catalysts are used in the Qatar plant and for the planned plant in Nigeria.

- Sasol has already produced more than 1.5 billion barrels of fuels from coal.
- Sasol has signed agreements with two Chinese companies for two CTL projects in China at a cost of between $5 billion to $7 billion each. Each plant will have a liquids production capacity of 80,000 bbl/d and will consume between15 and 19 million tons of coal per year.
- Sasol has been in discussions with various entities in the USA but up to now no announcements were made to indicate that there are serious projects being planned.
- Sasol announced that it is evaluating a Sasol Four in South Africa (CTL).

- **Sasol and Shell.**
  - Sasol and Shell are collaborating in the 5,000 bbl/d CTL WMPI project in Gilberton, PA with Shell providing the gasifier and Sasol the FT part. It will co-produce 41MW of power. DOE indicated a willingness to contribute $100 million to the project which was initially estimated at $615 million, but is now likely to be closer to $1 billion. This project has still not formally kicked off at the time of writing.

- **Shell.** Shell and Anglo American recently announced an agreement to evaluate a lignite–to-liquids (CTL) project in Victoria, Australia.

- **Syntroleum.**
  - Syntroleum has an agreement with Linc Energy in Australia for converting syngas from underground gasification to FT products. The plans call for the eventual production of 14,000 bbl/d and BP undertook to buy the products.
  - Syntroleum plans a project together with Sustec (recently taken over by Siemens) and intend a 3,000 bbl/d FT project in Germany. This is intended as a cobalt-based slurry reactor system. The next phase is targeted at 20,000 bbl/d. The feed is lignite and the project is supported by the Saxony State Government.

Related Natural Gas-to-Liquids (GTL) Projects

- **Sasol.** Sasol has just completed a GTL facility called Oryx GTL in partnership with Qatar Petroleum in Qatar. First products are being shipped. It is a 34,000 bbl/d facility – currently the largest GTL facility in the world and expansions are planned. It was completed at a cost of about $1 billion (just below $30,000 per daily barrel) and is the first GTL project financed on a limited-recourse basis.

- **ExxonMobil.** Exxon did extensive research on FT in the 1980'2 and early 1990's and have successfully ran a 200 bbl/d GTL unit in Baton Rouge to validate their designs. They planned a commercial facility in Qatar, but recently little was published on their plans. They have covered the field of FT catalysis and technology with an extensive portfolio of patents.

- **Shell.** A planned Shell GTL project in Qatar of 140,000 bbl/d, called the Pearl project, will use KBR, a Halliburton subsidiary (jointly with JVC of Japan), as its EPC contractor. The project is under review due to unexpected cost increases.

- **Syntroleum.** Syntroleum recently announced that it is closing its 70 bbl/d GTL facility (some sources indicates 100 bbl/d) and laid off about 1/3 of its staff. This facility produced large quantities of FT product for testing by the DOD in military aircraft.

Gasification for Power Generation/Other Applications

- **Conoco-Phillips.** The E-gas technology is now owned by ConocoPhillips. This technology has been demonstrated in the Wabash IGCC facility and the new designs incorporate the lessons learned from the commercial operations at this plant.

- **KRB.** KRB's Transport Bed Gasifier was operated at a pilot scale in Wilsonville, AL and has been selected by the DOE to be commercialized in Florida.

- **Sasol.** Sasol has a joint venture with Lurgi, called Sasol-Lurgi for the commercialization of the Lurgi gasification technology.

- **GE.**
    - GE took over the Texaco gasification technology a few years ago and is actively promoting the technology in a number of ventures, especially IGCC projects. This technology has been demonstrated in the Tampa IGCC facility and is analogous to that successfully operated for more than 20 years by Eastman Chemicals in Kingsport, TN.
    - The GE gasifier is now being considered for a number of IGCC facilities, such as the ERORA projects in Illinois and Kentucky.

- **Siemens.** Siemens has taken over the German Future Energy gasification technology and is now promoting it under the new company name Sustec (see Syntroleum above).

- **EnviRes.** EnviRes (a Kentucky company) has been promoting a coal to syngas route via a molten iron process. This project, which received DOE support at the testing phase still needs prototype demonstration.

- **Shell.** Shell is now promoting its gasifier in combination with its FT technology, after it has for many years focused on GTL

Engineering, Procurement and Construction Companies

- **Chevron-Sasol-Foster Wheeler.** Foster Wheeler provided engineering services for the Sasol facilities in Qatar as well as the Chevron-Sasol venture in Nigeria.

- **Conoco Phillips-GE-Flour Daniel.** ConocoPhillips collaborated with Fluor Daniel as EPC contactor and GE as turbine supplier for the IGCC at Wabash.

- **Nexant and Badger.** Other engineering contractors active in the field include Nexant and Badger.

IV. Role of Government

The Energy Policy Act of 2005 provides incentives for deployment of CTL and SNG. Legislative measures are being proposed as this report is written to further provide incentives in different forms, including providing product off-take agreements for CTL fuels which would be used by the military as jet fuels. Mechanisms such as loan guarantees and tax incentives are provided for qualifying projects and it is beyond the scope of this study to elaborate on these additional funding avenues which are available to entities which are deploying these technologies. It is appropriate for the Federal Government to provide such stimulus at the national level.

Similarly it can be argued that it is also appropriate for the state and local authorities to work closely with industries and project developers to smooth the path towards successful commercialization. Such support could include expeditious attention to permitting, provision of needed infrastructure which will be valuable to citizens in the particular area and also working with local communities and interest groups to ensure that potential concerns are identified early and that involved parties are fully informed of the considerations for siting and operating such facilities. *The American Energy Security Study* of the Southern States Energy Board provides an excellent compendium of the many approaches government can take to stimulate deployment (http://www.americanenergysecurity.org/studyrelease.html).

In this report the initiatives which various states have taken to provide incentives for the deployment of clean coal facilities are not covered, but it needs to be mentioned that such incentives and expressions of state support are key considerations for encouraging industries to site their facilities in those states. It should also be stressed that the incentives, although potentially substantial on their own, are important to contribute to risk reduction for financing a project but would not directly deal with the issue of the high level of capital investment which is typical for this industry. The capital would still be primarily made available by equity investors with an appropriate financing plan.

The question that begs to be answered is: What can be done to provide an opportunity for Kentucky to again regain its position as a leading state in the US regarding energy, and specifically CTL and SNG? Some brief pointers are presented for consideration:

- The Commonwealth should make it a funded priority to take on this role which could lead to substantial economic benefits to Kentucky during the construction of such plants and even more so in a sustainable way once the facilities become operational.

- A strong team at Cabinet level should drive the initiatives to attract entrepreneurs and investors. Part of this action could be to bring the appropriate partners together, because as of now there are not many significant teams with the wherewithal to deal with large multi-billion projects, especially not a team of equipment vendors, EPC contractors as well as plant owners/operators in this field.

(Page left blank intentionally.)

UNIVERSITY OF KENTUCKY